Regulatory Impact Analysis of the

Final Oil and Natural Gas Sector: Emission

Standards for New, Reconstructed, and

Modified Sources

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EPA-452/R-16-002, May 2016

Regulatory Impact Analysis of the Final Oil and Natural Gas Sector:

Emission Standards for New, Reconstructed, and Modified Sources

U.S. Environmental Protection Agency

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ACKNOWLEDGEMENTS

In addition to U.S. EPA staff from the Office of Air and Radiation, personnel from the U.S. EPA

Office of Policy, EC/R Incorporated, and ICF International contributed data and analysis to this

document.



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# 1 EXECUTIVE SUMMARY

## 1.1 Background

The action analyzed in this regulatory impact analysis (RIA) amends the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this rule because methane is a greenhouse gas (GHG), and the oil and natural gas category is the country's largest emitter of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.

The EPA is amending the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category. Specifically, we are establishing both methane and VOC standards for several emission sources not covered by the 2012 NSPS (i.e., hydraulically fractured oil well completions, fugitive emissions from well sites, compressor stations, pneumatic pumps). In addition, we are establishing methane standards for certain emission sources that are regulated for VOC under the 2012 NSPS (i.e., hydraulically fractured gas well completions, equipment leaks at natural gas processing plants). However, we do not expect any incremental benefits or costs as a result from regulating methane for VOC sources regulated under the 2012 NSPS.

With respect to certain equipment that are used across the source category, the 2012 NSPS regulates only a subset of this equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The new amendents establish methane standards for these equipment across the source category and extend the VOC standards from the 2012 NSPS to the remaining unregulated equipment. Lastly, amendments to the 2012 NSPS are established that improve several aspects of the 2012 standards related to implementation. These improvements result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the 2012 NSPS for the oil and natural gas sector and related amendments. Except for these implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the 2012



standards.

As part of the regulatory process, the EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million annually. The EPA estimates the final NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. This RIA includes an economic impact analysis and an analysis of the climate, health, and welfare impacts anticipated from the final NSPS.[1] We also estimate potential impacts of the rule on national energy markets using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using 3 and 7 percent discount rates.

This analysis estimates regulatory impacts for the analysis years of 2020 to represent the near-term impacts of the rule, and 2025 to represent impacts of the rule over a longer period. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (i.e., including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Affected facilities are facilities that are new or modified since the proposal in September 2015. In 2020, affected facilities are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 through 2024 that are assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

Several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically-fractured oil wells, capture methane and VOC emissions that otherwise would be vented to the atmosphere. The averted methane emissions can be directed into natural gas production streams and sold. The revenues derived from natural gas recovery are expected to offset a portion of the engineering costs of implementing the NSPS. In this RIA, we present

1 The analysis in this RIA and the RIA that accompanied the proposal together constitute the economic assessment required by CAA section 317. In the EPA's judgment, the assessment is as extensive as practicable taking into account the EPA's time, resources, and other duties and authorities.



results that include the additional product recovery and the revenues we expect

producers to gain
from the additional product recovery.

The baseline used for the impacts analysis of our NSPS takes into account emissions reductions conducted pursuant to state regulations covering the relevant operations. A detailed discussion on the derivation of the baseline is presented in Section 3 of this RIA.

## 1.2 Market Failure

Many regulations are promulgated to correct market failures, which lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address "negative externalities" whereby the market does not internalize the full cost of production that is borne by society, as public goods such as air quality are unpriced.

Greenhouse Gas (GHG) and VOC emissions impose costs on society, such as negative climate, health, and welfare impacts. These impacts are not reflected in the market price of the goods produced through the polluting process and are referred to as negative externalities. For this regulatory action, the goods produced, processed, transported, or stored are crude oil, natural gas, and other hydrocarbon products. If an oil and natural gas firm pollutes the atmosphere while extracting, processing, transporting, or storing goods, this cost will not be borne by the polluting firm but by society as a whole. The market price of the products will fail to incorporate the full cost to society of the pollution related to production. All else held equal, the quantity of oil and natural gas produced in a competitive market will not be at the socially optimal level. More oil and natural gas will be produced than would occur if the oil and natural gas producers had to account for the full cost of production, including the negative externality. Consequently, absent a regulation on emissions, the marginal social cost of the last units of oil and natural gas produced will exceed its marginal social benefit.

## 1.3 Regulatory Options Analyzed in this RIA

In this RIA, we examine three broad regulatory options. Table 1-1 shows the emissions sources, points, and controls for the three NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3. Option 2 was selected for promulgation.



Table 1-1 Emissions Sources and Controls Evaluated for the NSPS

Emissions Point Emissions Control

Option 1

Option 2

(final)

Option 3

Well Completions and Recompletions

Hydraulically Fractured

Development Oil Wells

REC / Combustion X X X

Hydraulically Fractured Wildcat

and Delineation Oil Wells

Combustion X X X

Fugitive Emissions

Well Sites

Planning,

Monitoring and

Maintenance

Annual Semiannual Quarterly

Gathering and Boosting Stations

Planning,

Monitoring and

Maintenance

Semiannual Quarterly Quarterly

Transmission Compressor Stations

Planning,

Monitoring and

Maintenance

Semiannual Quarterly Quarterly

Pneumatic Pumps

Well Sites Route to control X X X

Pneumatic Controllers

Natural Gas Transmission and

Storage

Emissions limit X X X

Reciprocating Compressors

Natural Gas Transmission and

Storage

Maintenance X X X

Centrifugal Compressors

Natural Gas Transmission and

Storage

Route to control X X X

Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, and pneumatic controllers and pumps.

Options 1 and 3 differ from the finalized Option 2 with respect to the requirements for fugitive emissions. Well site fugitive requirements under Option 1 are annual, while new or



modified gathering and boosting station and new or modified transmission and storage compressor stations require a semiannual fugitive emission survey and repair program. Less frequent survey requirements lead to lower costs as well as lower emissions reduction compared to the selected Option 2. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. More frequent surveys result in greater emission reductions, however there are also increased costs, resulting in a net effect of lower net benefits compared to the finalized Option 2.

## 1.4 Summary of Results

For the final NSPS, a summary of the key results of the RIA for the final standards (Option 2) follow. Key results for Options 1 through 3 are summarized in Table 1-2 through Table 1-4, respectively. Note all dollar estimates are in 2012 dollars:

• Emissions Analysis: The final NSPS is anticipated to prevent significant new emissions, including 300,000 short tons of methane, 150,000 tons of VOCs and 1,900 tons of hazardous air pollutants (HAP) in 2020, increasing to 510,000 short tons of methane, 210,000 tons of VOCs, and 3,900 tons of HAP prevented in 2025.2 The CO2-equivalent (CO2 Eq.) methane emission reductions are 6.9 million metric tons in 2020 and 11 million metric tons in 2025.

• Benefits Analysis: The monetized benefits in this RIA include those from reducing methane emissions, which are valued using the social cost of methane (SC-CH4).3 The EPA estimates that, in 2020, the rule will yield monetized climate benefits of $160 million to approximately $950 million; the mean SC-CH4 at the 3% discount rate results in an estimate of about $360 million in 2020. In 2025, the EPA estimates monetized climate benefits of $320 million to approximately $1.8 billion; the mean SC-CH4 at the 3% discount rate results in an estimate of about $690 million in 2025.4 While we expect that the avoided emissions will result in improvements in ambient air quality and reductions in negative health effects associated with exposure to HAP, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule.5 This is not to imply that there are no health benefits

2 Estimates are presented in short tons.

3 The social cost of methane (SC-CH4) is the monetary value of impacts associated with a marginal change in methane emissions in a given year.

4 The range of estimates reflects four SC-CH4 estimates and are associated with different discount rates (model average at 2.5, 3 and 5 percent; 95th percentile at 3 percent). See Section 4.3 for a complete discussion.

5 Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient PM2.5 levels and the health effects associated with PM2.5 exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in



anticipated from the final NSPS; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits.

• Engineering Cost Analysis: The EPA estimates the total capital cost of the final NSPS to be $250 million for affected sources in 2020 and $360 million for affected sources in 2025. The estimate of total annualized engineering costs of the final NSPS is $390 million in 2020 and $640 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the NSPS are estimated to be $320 million in 2020 and $530 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). The estimated engineering compliance costs that include product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $16 million in 2020 and $27 million in 2025, given the EPA estimates that about 16 million Mcf in 2020 and 27 million Mcf of natural gas will be recovered by implementing the NSPS. When using a 3 percent discount rate, the estimate of total annualized engineering costs of the final NSPS is $380 million in 2020 and $630 million in 2025, or $320 million in 2020 and $520 million in 2025, when estimated revenues from additional natural gas are included.

• Energy Markets Impacts Analysis: The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the final rule on the United States energy markets. We estimate that natural gas and crude oil drilling levels decline slightly over the 2020 to 2025 period relative to the baseline (by about 0.17 percent for natural gas wells and about 0.02 percent for crude oil wells). Natural gas production decreases slightly over the 2020 to 2025 period under the rule relative to the baseline (by about 0.03 percent), while crude oil production does not vary appreciably. Crude oil wellhead prices for onshore lower 48 production are not estimated to change appreciably over the 2020 to 2025 period relative to the baseline. However, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly over the 2020 to 2025 period relative to the baseline (about 0.20 percent). Net imports of natural gas are estimated to increase slightly over the 2020 to 2025 period (by about 0.11 percent) relative to the baseline. Crude oil net imports are not estimated to to change appreciably over the 2020 to 2025 period relative to the baseline.

• Small Entity Analyses: To understand the potential impact of the rule on small entities, the EPA conducted a screening analysis of the potential impacts by estimating the ratio of potential compliance costs to firm sales (i.e. a cost-to-sales test). Based on the results of this screening analysis, the EPA concluded that it is unable to certify that the final rule

that study are derived from total VOC emissions across all sectors. Larger uncertainties about the relationship between VOC emissions and PM2.5 coupled with the highly localized nature of air quality responses associated with VOC reductions, lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to

calculate monetized benefits of these rules, even as a bounding exercise.



will not have a Significant Impact on a Substantial Number of Small Entities (SISNOSE). The EPA convened a Small Business Advisory Review panel and completed an Inititial Regulatory Flexibility Analysis before proposing the rule. The EPA also completed a Final Regulatory Flexibility Analysis for the final rule.

• Employment Impacts Analysis: The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment and control activities, as well as the labor associated with new reporting and recordkeeping requirements. The EPA estimated one-time and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The one-time labor requirement to comply with the final NSPS is estimated at about 270 FTEs in 2020 and in 2025. The annual labor requirement to comply with the NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. The EPA notes that this type of FTE estimate cannot be used to identify the specific number of employees involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 1-2 presents the summary results for Option 1, Table 1-3 presents summary results for Option 2, and Table 1-4 presents summary results for Option 3.



Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012$)

| | 2020 | 2025 |
|---|---|---|
| Total Monetized Benefits1 | $290 million | $540 million |
| Total Costs2 | $240 million | $360 million |
| Net Benefits3 | $54 million | $180 million |
| Non-monetized Benefits | | |
| | Non-monetized climate benefits | Non-monetized climate benefits |
| | Health effects of PM2.5 and ozone exposure from 130,000 tons of VOC reduced | Health effects of PM2.5 and ozone exposure from 170,000 tons of VOC reduced |
| | Health effects of HAP exposure from | |

1,300 tons of HAP reduced

Health effects of HAP exposure from

2,700 tons of HAP reduced

Health effects of ozone exposure from

250,000 tons of methane

Health effects of ozone exposure from

390,000 tons of methane

Visibility impairment Visibility impairment

Vegetation effects Vegetation effects

1 The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH4)

(model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of

this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we

emphasize the importance and value of considering the benefits calculated using all four SC-CH4 estimates; the

additional benefit estimates range from $130 million to $780 million in 2020 and $250 million to $1.4 billion in

2025 for Option 1, as shown in Section 4.3. The CO2-equivalent (CO2 Eq.) methane emission reductions are 5.6

million metric tons in 2020 and 8.9 million metric tons in 2025. Also, the specific control technologies for the

NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

2 The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue

from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the

national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate

in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for

annualizing capital costs.

3 Estimates may not sum due to independent rounding.



Table 1-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 2

(Finalized Option) in 2020 and 2025 (2012$)

2020 2025

Total Monetized Benefits1 $360 million $690 million

Total Costs2 $320 million $530 million

Net Benefits3 $35 million $170 million

Non-monetized Benefits Non-monetized climate benefits Non-monetized climate benefits

Health effects of PM2.5 and ozone

exposure from 150,000 tons of VOC

reduced

Health effects of HAP exposure from

1,900 tons of HAP reduced

Health effects of ozone exposure from

300,000 tons of methane

Health effects of PM2.5 and ozone

exposure from 210,000 tons of VOC

reduced

Health effects of HAP exposure from

3,900 tons of HAP reduced

Health effects of ozone exposure from

510,000 tons of methane

Visibility impairment Visibility impairment

Vegetation effects Vegetation effects

1 The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH4)

(model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table,

we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the

importance and value of considering the benefits calculated using all four SC-CH4 estimates; the additional

benefit estimates range from $160 million to $950 million in 2020 and $320 million to $1.8 billion in 2025 for

Option 2, as shown in Section 4.3. The CO2-equivalent (CO2 Eq.) methane emission reductions are 6.9 million

metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the NSPS are

anticipated to have minor secondary disbenefits. See Section 4.7 for details.

2 The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue

from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the

national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate

in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for

annualizing capital costs.

3 Estimates may not sum due to independent rounding.



Table 1-4 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in

2020 and 2025 (2012$)

2020 2025

Total Monetized Benefits1 $420 million $840 million

Total Costs2 $490 million $880 million

Net Benefits3 -$75 million -$38 million

Non-monetized Benefits

Non-monetized climate benefits Non-monetized climate benefits

Health effects of PM2.5 and ozone

exposure from 160,00 tons of VOC

reduced

Health effects of PM2.5 and ozone

exposure from 230,000 tons of VOC

reduced

Health effects of HAP exposure from

2,400 tons of HAP reduced

Health effects of HAP exposure from

5,000 tons of HAP reduced

Health effects of ozone exposure from

350,000 tons of methane

Health effects of ozone exposure from

610,000 tons of methane

Visibility impairment Visibility impairment

Vegetation effects Vegetation effects

1 The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH4)

(model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table,

we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the

importance and value of considering the benefits calculated using all four SC-CH4 estimates; the additional

benefit estimates range from $190 million to $1.1 billion in 2020 and $390 million to $2.2 billion in 2025 for this

more stringent option, as shown in Section 4.3. The CO2-equivalent (CO2 Eq.) methane emission reductions are 8

million metric tons in 2020 and 14 million metric tons in 2025. Also, the specific control technologies for the

NSPS are anticipated to have minor secondary disbenefits.

2 The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue

from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the

national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for

annualizing capital costs.

3 Estimates may not sum due to independent rounding.

1.5 Summary of NSPS Impacts Changes from the Proposal RIA

This section summarizes major changes from the proposal version of the RIA. These

changes were a result of revised assumptions and technical factors, as well as changes in the rule

itself from proposal. With respect to changes in the rule's provisions from proposal, we focus on

changes that have an effect on estimates of emissions reductions, costs, and benefits.

Changes resulting from revised assumptions and technical factors include:

• Annual Energy Outlook and National Energy Modeling System updates: At

proposal, the Energy Information Administration (EIA) 2014 Annual Energy Outlook

(AEO) was used to derive projections of oil and natural gas well drilling activities. For

this RIA, we used the 2015 AEO, the latest version available at the time of the signature

of the rule. Section 3.4.2 presents a brief discussion comparing the 2014 and 2105 AEOs.



The EPA also updated the version of the NEMS model from 2014 to 2015 to develop the

energy markets impacts presented in Section 6.2 of this RIA.

• EPA Greenhouse Gas Inventory updates: The EPA updated the unit-level cost and

emissions analyses where possible to reflect recent updates to the Greenhouse Gas

Inventory. In particular, data from the Greenhouse Gas Reporting program and the

Greenhouse Gas Inventory was used to update the equipment and component counts and

potential emissions of the model plants for fugitive emissions.

• Revised first year of regulatory program: At proposal, 2020 was assumed to represent

a single year of potential impacts. However, NSPS-affected facilities are facilities that are

new or modified since the proposal in September 2015. In this final RIA, affected

facilities in 2020 are those that are newly established or modified in 2020, as well as

those that have accumulated between 2016 and 2019. As a result, the years of analysis in

this RIA are 2020, to represent the near-term impacts of the rule, and 2025, to represent

impacts of the rule over a longer period. This methodological change results in a higher

estimate of the number of affected facilities than at proposal and better represents the

impacts of the rule.

• New hydraulically fractured oil well completions with insufficient pressure to implement REC required to combust completions emissions: Using the formula estimated to identify hydraulically fractured well completions that would not have sufficient pressure to perform a REC, approximately 40 percent of oil well completions that would otherwise be required to perform a REC would be required to combust emissions rather than implement a REC. The overall proportion of completions that are assumed to be feasible to REC remains unchanged from the proposal analysis at 50 percent. More detailed discussion is presented in a technical memorandum on this subject in the docket.6

• Revised unit-level emissions and cost estimates: The EPA revised the cost of control esimates for fugitive emissions monitoring and pneumatic pumps based on information provided by commenters.

• Revised approach to projecting affected facilities from historical activity data: Newly constructed affected facilities are estimated based on averaging the year-to-year changes in the past 10 years of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps, compressors, and controllers. At proposal, this was done by averaging the increasing years only. The approach was modified to average the number of newly constructed units in all years.

The changes in the rules requirements that affect emissions, cost, and benefit estimates include:

• Fugitive emissions: The EPA proposed to exclude low production well sites (e.g., well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the standards for the collection of fugitive emissions components at well sites. Based on

6 [Placeholder for title of low pressure well eequation technical memo]



analysis in response to comments, the EPA is finalizing the requirement that low production well sites are regulated under a monitoring and repair standard based on semiannual monitoring. With respect to fugitive emissions at compressor stations, based on analysis in response to comments, the EPA is finalizing the requirement to implement the fugitives program at compressor stations on a quarterly basis, as opposed to the proposed semiannual (twice per year) basis.

• Hydraulically fractured oil well completions: For the final rule, the EPA refined requirements that require wells that are not low GOR, low pressure, or exploration/delineation wells to have a separator on site during completion flowback. Wells with low GOR (less than 300 scf/of gas per stock barrel of oil produced) are still excluded from well completion requirements, but, unlike at proposal, they are considered affected facilities and their exclusion from requirements is provided the owner or operator maintains records of the low GOR certification, and submit a claim signed by the certifying official.

• Pneumatic pumps: The EPA changed the definition of an affected pneumatic pump facility to include only natural gas driven pumps in order to incentivize the use of lower emitting alternatives. The EPA also exempted chemical injection pumps and portable or temporary pumps from control requirements.

1.6 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents a comparison of benefits and costs. Section 6 presents energy markets impact, employment impact, and small entity impact analyses.



# 2 INDUSTRY PROFILE

## 2.1 Introduction

The oil and natural gas industry includes five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS require controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210-Pipeline Transportation of Natural Gas. While other NAICS (221210-Natural Gas Distribution, 486110-Pipeline Transportation of Crude Oil, and 541360-Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the final NSPS.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2014, the Energy Information Administration (EIA) estimates that about 515,000 producing natural gas wells are operating in the U.S. The latest available information from EIA indicates that there were about 536,000 producing oil wells in the U.S. as of 2011. Domestic dry natural gas production was 25.7 trillion cubic feet (tcf) in 2014, the highest annual production level in U.S. history. The leading five natural gas producing states in 2014 were Texas, Pennsylvania, Oklahoma, Louisiana and Wyoming. Domestic crude oil production in 2014 was 3,200 million barrels (bbl), the highest annual level in the U.S. since 1991. The leading five crude oil producing states in 2014 were Texas, North Dakota, California, Alaska, and Oklahoma.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the NSPS. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analyses in this RIA. The Industry Profile relies heavily on background material from the EPA's "Economic Analysis of Air Pollution Regulations: Oil and



Natural Gas Production" (1996), the EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000), and the EPA's "Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry" (2012).

## 2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and the natural gas as well as the reservoir characteristics are likely to be different across all reservoirs.

### 2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another method to classify hydrocarbons, including crude oil, is through the measurement of API gravity. API gravity is a weight per-unit of volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with an API gravity of 20o or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has an API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase may be referred to as live crudes. Live crudes contain entrained or dissolved gases that may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.



2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exist in a gaseous phase or in a solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide ($H_2S$), $CO_2$, mercaptans, and entrained solids.

Natural gas may be classified as a wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas is classified as acid, sour or sweet. Acid gas contains $CO_2$ and/or $H_2S$, where the concentration of $H_2S$ is below the threshold to be classified as sour. Acid gas may contain other contaminants. Natural gas is classified as sour when it contains an $H_2S$ concentration of greater than 0.25 grains per 100 standard cubic feet. Sour gas may also contain other contaminants. Concentrations of $H_2S$ and $CO_2$, along with organic sulfur compounds, vary widely among sour gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening, most commonly performed through amine treating. A majority of total onshore natural gas production and nearly all offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40o or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.



2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either well completion if hydrocarbons are found in sufficient quantities, or to abandonment otherwise.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper, sections of drill pipe are added. A mix of fluids called drilling mud are released down into the drill pipe, which then push up the walls of the well bore, removing drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out ("blowing out").

The well bore is cased in with telescoping steel piping during drilling to avoid its collapse, to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore



allowing more oil or natural gas to move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as "fracking") has been performed since the 1940s (U.S. DOE, 2013). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant, a mixture of sand and other materials, is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

### 2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because the well is usually drilled into the bottom, oil-heavy portion of a formation to recover most of the liquid first, with the natural gas



cap sitting on top. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During primary extraction, pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). When the well lacks enough pressure itself to drive the resource to the surface, gas or water is injected into the well to increase the well pressure and force the resource out (secondary or improved oil recovery). Finally, in tertiary extraction or enhanced recovery, gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock, sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2013). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional oil and natural gas resource types relevant for this rule include:

• Shale Oil and Natural Gas: Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2013).

• Tight Sands Natural Gas: Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2013).

• Coalbed Methane: Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).



2.3.3 Natural Gas Processing

As natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems. Natural gas conditioning is the process of removing impurities from the gas stream so it is of sufficient quality to pass through transportation systems and to be used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline.

One concern in natural gas processing is posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquid at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid desiccant, a solid desiccant, or refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration and the glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract water molecules. The solids can be regenerated by heating them above the boiling point of water and then be reused as well. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

The most significant impurity in natural gas is H2S, which may or may not be contained in natural gas. H2S is toxic and potentially fatal, at certain concentrations, to humans and it is corrosive to pipes. It is therefore desirable to remove H2S as soon as possible in the conditioning process.

Sweetening, the procedure in which H2S and sometimes CO2 are removed from the gas stream, is most commonly performed using amine treatment. In this process, the gas stream is



exposed to an amine solution, which will react with H2S and separate it from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to increase pressure to improve the movement of natural gas through transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

## 2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.



### 2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and dry natural gas proved reserves, unproved reserves, and total technically recoverable resources as of 2009. The EIA7 defines these concepts as:

- Proved reserves: estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.
- Unproved resources: additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology.
- Total technically recoverable resources: resources that are producible using current technology without reference to the economic viability of production.

According to the EIA, dry natural gas is consumer-grade natural gas. The dry natural gas volumes reported in Table 2-1 reflect the amount of gas remaining after the liquefiable portion and any non-hydrocarbon gases that render it unmarketable have been removed from the natural gas. The sum of proved reserves and unproved reserves equal the total technically recoverable resources. As seen in Table 2-1, as of 2009, proved domestic crude oil reserves accounted for about 10 percent of the total technically recoverable crude oil resources.

Total proved natural gas reserves, accounted for about 12 percent of the total technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and in offshore areas. While dry natural gas proved reserves were estimated at 272.5 tcf in 2009, wet natural gas reserves were estimated at 283.9 tcf. Of the 283.9 tcf, 250.5 tcf (about 88 percent) were considered to be wet non-associated natural gas, while 33.3 tcf (about 12 percent) were considered to be wet associated-dissolved natural gas. Associated-dissolved natural gas,

according to EIA, is natural gas that occurs in crude oil reservoirs as free natural gas or in

solution with crude oil.

7 U.S. Department of Energy, Energy Information Administration, Glossary of Terms

<http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

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Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource

Estimates, 2009

Region Proved Reserves

Unproved

Resources

Total Technically

Recoverable

Resources

Crude Oil and Lease Condensate (billion barrels)

48 States Onshore 14.2 112.6 126.7

48 States Offshore 4.6 50.3 54.8

Alaska 3.6 35.0 38.6

Total U.S. 22.3 197.9 220.2

Dry Natural Gas (trillion cubic feet)

Conventionally Reservoired Fields 105.5 904.0 1,009.5

48 States Onshore 1 81.4 369.7 451.1

48 States Offshore 15.0 262.6 277.6

Alaska 9.1 271.7 280.8

Tight Gas, Shale Gas and Coalbed Methane 167.1 1,026.7 1,193.8

Total U.S. 272.5 1,930.7 2,203.3

Source: U.S. Energy Information Administration, Annual Energy Review 2012. Totals may not sum due to

independent rounding.

1 Includes associated-dissolved natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas

in solution with crude oil (dissolved gas).

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves

from 1990 to 2014. In Table 2-2, proved ultimate recovery equals the sum of cumulative

production and proved reserves. Cumulative production is the accumulated crude oil or dry

natural gas that has been produced over time. While crude oil and natural gas are nonrenewable

resources, the table shows that proved ultimate recovery rises over time as new discoveries

become economically accessible. Reserves growth and decline is also partly a function of

exploration activities, which are correlated with oil and natural gas prices. For example, when oil

prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to

develop unconventional sources. Annual production (the difference in cumulate production over

one year) as a percentage of proved reserves has declined over time for both crude oil and natural

gas from around 11 percent in the early 1990s to between 8 and 10 percent over the period from

2006 to 2014 for crude oil and from about 10 percent during the early 1990s to between 7 and 9

percent from 2006 to 2014 for natural gas.



Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved

Reserves, and Proved Ultimate Recovery, 1990-2014

| | Crude Oil and Lease Condensate (million barrels) | | | Dry Natural Gas (Billion Cubic Feet or bcf) | | |
|---|---|---|---|---|---|---|
| | Cumulative Production | Proved Reserves | Proved Ult. Recovery | Cumulative Production | Proved Reserves | Proved Ult. Recovery |
| 1990 | 158,175 | 26,254 | 184,429 | 744,546 | 169,346 | 913,892 |
| 1991 | 160,882 | 24,682 | 185,564 | 762,244 | 167,062 | 929,306 |
| 1992 | 163,507 | 23,745 | 187,252 | 780,084 | 165,015 | 945,099 |
| 1993 | 166,006 | 22,957 | 188,963 | 798,179 | 162,415 | 960,594 |
| 1994 | 168,437 | 22,457 | 190,894 | 817,000 | 163,837 | 980,837 |
| 1995 | 170,831 | 22,351 | 193,182 | 835,599 | 165,146 | 1,000,745 |
| 1996 | 173,197 | 22,017 | 195,214 | 854,453 | 166,474 | 1,020,927 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1997 | 175,552 | 22,546 | 198,098 | 873,355 | 167,223 | 1,040,578 |
| 1998 | 177,834 | 21,034 | 198,868 | 892,379 | 164,041 | 1,056,420 |
| 1999 | 179,981 | 21,765 | 201,746 | 911,211 | 167,406 | 1,078,617 |
| 2000 | 182,112 | 22,045 | 204,157 | 930,393 | 177,427 | 1,107,820 |
| 2001 | 184,229 | 22,446 | 206,675 | 950,009 | 183,460 | 1,133,469 |
| 2002 | 186,326 | 22,677 | 209,003 | 968,937 | 186,946 | 1,155,883 |
| 2003 | 188,388 | 21,891 | 210,279 | 988,036 | 189,044 | 1,177,080 |
| 2004 | 190,379 | 21,371 | 211,750 | 1,006,627 | 192,513 | 1,199,140 |
| 2005 | 192,270 | 21,757 | 214,027 | 1,024,677 | 204,385 | 1,229,062 |
| 2006 | 194,127 | 20,972 | 215,099 | 1,043,181 | 211,085 | 1,254,266 |
| 2007 | 195,981 | 21,317 | 217,298 | 1,062,447 | 237,726 | 1,300,173 |
| 2008 | 197,811 | 19,121 | 216,932 | 1,082,605 | 244,656 | 1,327,261 |
| 2009 | 199,765 | 20,682 | 220,447 | 1,103,229 | 272,509 | 1,375,738 |
| 2010 | 201,764 | 23,267 | 225,031 | 1,124,545 | 304,625 | 1,429,170 |
| 2011 | 203,822 | 26,544 | 230,366 | 1,147,447 | 334,067 | 1,481,514 |
| 2012 | 206,192 | 30,529 | 236,721 | 1,171,480 | 308,036 | 1,479,516 |
| 2013 | 208,913 | 33,371 | 242,284 | 1,195,685 | 338,264 | 1,533,949 |
| 2014 | 212,092 | 36,385 | 248,477 | 1,221,414 | 368,704 | 1,590,118 |

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas

Proved Reserves, 2014. Table 7 and Table 17.

<http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>. Accessed January 15, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014.

<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production.

<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm>. Accessed on January 29, 2016.

Note: Cumulative Crude Oil Production includes Crude Oil plus Lease Condensate Production.

Note: The EIA reports Proved Reserves for Crude Oil and Proved Reserves for Crude Oil plus Lease Condensate

separately. We have reported Proved Reserves for Crude Oil here.

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Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-

2013. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2013

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas

Proved Reserves, 2014. Table 7 and Table 17. <http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>.

Accessed January 15, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014.

<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production.

<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm>. Accessed on January 29, 2016.

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or

producing area as of 2014. Five areas currently account for 79 percent of total proved reserves of

crude oil in the U.S., led by Texas and followed by North Dakota, U.S. Federal Offshore, Alaska,

and California. The top five states in terms of proved reserves of natural gas, Texas,



Pennsylvania, Oklahoma, West Virginia, and Wyoming, account for about 67 percent of the U.S.

total proved natural gas reserves.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2013

| State/Region | Crude Oil (million bbls) | Dry Natural Gas (bcf) | Crude Oil (% of total) | Dry Natural Gas (% of total) |
|---|---|---|---|---|
| Alabama | 66 | 2,036 | 0.2 | 0.6 |
| Alaska | 2,855 | 6,745 | 7.8 | 1.8 |
| Arkansas | 65 | 12,789 | 0.2 | 3.5 |
| California | 2,854 | 2,107 | 7.8 | 0.6 |
| Colorado | 1,200 | 20,851 | 3.3 | 5.7 |
| Florida | 70 | 0 | 0.2 | 0.0 |
| Kansas | 414 | 4,359 | 1.1 | 1.2 |
| Kentucky | 16 | 1,611 | 0.0 | 0.4 |
| Louisiana | 534 | 22,975 | 1.5 | 6.2 |
| Michigan | 53 | 1,845 | 0.1 | 0.5 |
| Miscellaneous States ** | 84 | 2,976 | 0.2 | 0.8 |
| Mississippi | 230 | 558 | 0.6 | 0.2 |
| Montana | 444 | 667 | 1.2 | 0.2 |
| New Mexico | 1,476 | 15,283 | 4.1 | 4.1 |
| New York | * | 143 | * | 0.0 |

North Dakota 6,043 6,034 16.6 1.6

Ohio 78 6,723 0.2 1.8

Oklahoma 1,241 31,778 3.4 8.6

Pennsylvania 22 59,873 0.1 16.2

Texas 12,272 97,154 33.7 26.4

U.S. Federal Offshore 4,849 8,527 13.3 2.3

Utah 555 6,685 1.5 1.8

West Virginia 11 29,432 0.0 8.0

Wyoming 953 27,553 2.6 7.5

Total Proved Reserves 36,385 368,704 100.0 100.0

Source: U.S. Energy Information Administration (U.S. EIA). November 2015. U.S. Crude Oil and Natural Gas

Proved Reserves, 2014. Table 7 and Table 17.

<http://www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf>. Accessed January 15, 2016.

Total may not sum due to independent rounding.

* New York crude oil reserves are included in miscellaneous states

**Miscellaneous for crude oil includes Arizona, Idaho, Missouri, Nevada, New York, South Dakota, Tennessee &

Virginia as well as Illinois, Indiana, and Nebraska.

**Miscellaneous for dry natural gas includes Arizona, Idaho, Illinois, Indiana, Maryland, Missouri, Nebraska,

Oregon, South Dakota & Tennessee as well as Virginia.

2.4.2 Domestic Production

Domestic oil production was in a state of decline that began in 1970 and continued to a

low point in 2008. As of 2014, domestic oil production has recovered to the highest levels since

1991. Table 2-4 shows U.S. production in 2014 at 3,179 million bbl per year.



Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average

First Purchase Price, 1990-2014

Total

Production

(million barrels)

Producing Wells

(1000s)

Avg. Well

Productivity

(bbl/well)

US Average

First Purchase

Price/Barrel

(nominal

dollars)

US Average

First Purchase

Price/Barrel

(2012 dollars)

1990 2,685 602 4,460 20.03 31.56

1991 2,707 614 4,409 16.54 25.22

1992 2,625 594 4,419 15.99 23.84

1993 2,499 584 4,279 14.25 20.75

1994 2,431 582 4,178 13.19 18.81

1995 2,394 574 4,171 14.62 20.42

1996 2,366 574 4,122 18.46 25.32

1997 2,355 573 4,110 17.23 23.24

1998 2,282 562 4,060 10.87 14.50

1999 2,147 546 3,932 15.56 20.45

2000 2,131 534 3,990 26.72 34.33

2001 2,118 530 3,995 21.84 27.44

2002 2,097 529 3,963 22.51 27.85

2003 2,062 513 4,019 27.56 33.43

2004 1,991 510 3,905 36.77 43.41

2005 1,891 498 3,798 50.28 57.51

2006 1,857 497 3,737 59.69 66.24

2007 1,853 500 3,706 66.52 71.90

2008 1,830 526 3,479 94.04 99.69

2009 1,954 526 3,715 56.35 59.29

2010 1,999 520 3,844 74.71 77.66

2011 2,058 536 3,840 95.73 97.50

2012 2,370 N/A N/A 94.52 94.52

2013 2,721 N/A N/A 95.99 94.45

2014 3,179 N/A N/A 87.39 84.60

Source: U.S. Energy Information Administration (U.S. EIA). Crude Oil Production.

<http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm>. Accessed on January 29, 2016.

Source: U.S. Energy Information Administration (U.S. EIA). U.S. Crude Oil First Purchase Price.

<https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=f000000__3&f=a>. Accessed on January 22, 2016.

Source: Federal Reserve Bank of St. Louis. Economic Research. Gross Domestic Product: Implicit Price Deflator.

<https://research.stlouisfed.org/fred2/series/GDPDEF>. Accessed February 3, 2016.

Note: First purchase price represents the average price at the lease or wellhead at which domestic crude is

purchased. Prices adjusted using GDP Implicit Price Deflator.

Note: Total Production includes Crude Oil plus Lease Condensate Production.

Average well productivity has also generally decreased since 1990 (Table 2-4 and Figure

2-2), though there are signs of a slight rebounding starting around 2008. These overall

production and productivity decreases are in spite of the fact that average first purchase prices

have generally shown an increasing trend with some decline in 2014.



Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-

2011. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2014.

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014.

<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.

Annual production of natural gas from natural gas wells has increased more than 8000

bcf from the 1990 to 2014 (Table 2-5). The number of wells producing natural gas has nearly

doubled between 1990 and 2014 (Figure 2-2B). While the number of producing wells has

increased overall, average well productivity has declined, despite improvements in exploration

and gas well stimulation technologies. Average well productivity has shown slight improvements

since 2009.

0

1,000

2,000

3,000

4,000

5,000

0

100

200

300

400

500

600

700

Crude Oil (bbl)/Well

Producing Wells

A). Crude Oil Wells

Producing Wells (1000s) Avg. Well Productivity (bbl/well)

2-16

Table 2-5 Natural Gas Production and Well Productivity, 1990-2014

Natural Gas Gross Withdrawals

(Billion Cubic Feet)

Natural Gas Well

Productivity

Total

Dry Gas

Production 1

Producing

Wells

Avg. Well

Productivity

Million Cubic

Feet/Year)

| | | | | |
|---|---|---|---|---|
| 1990 | 21,523 | 17,810 | 269,790 | 66.0 |
| 1991 | 21,750 | 17,698 | 276,987 | 63.9 |
| 1992 | 22,132 | 17,840 | 276,014 | 64.6 |
| 1993 | 22,726 | 18,095 | 282,152 | 64.1 |
| 1994 | 23,581 | 18,821 | 291,773 | 64.5 |
| 1995 | 23,744 | 18,599 | 298,541 | 62.3 |
| 1996 | 24,114 | 18,854 | 301,811 | 62.5 |
| 1997 | 24,213 | 18,902 | 310,971 | 60.8 |
| 1998 | 24,108 | 19,024 | 316,929 | 60.0 |
| 1999 | 23,823 | 18,832 | 302,421 | 62.3 |
| 2000 | 24,174 | 19,182 | 341,678 | 56.1 |
| 2001 | 24,501 | 19,616 | 373,304 | 52.5 |
| 2002 | 23,941 | 18,928 | 387,772 | 48.8 |
| 2003 | 24,119 | 19,099 | 393,327 | 48.6 |
| 2004 | 23,970 | 18,591 | 406,147 | 45.8 |
| 2005 | 23,457 | 18,051 | 425,887 | 42.4 |
| 2006 | 23,535 | 18,504 | 440,516 | 42.0 |
| 2007 | 24,664 | 19,266 | 452,945 | 42.5 |
| 2008 | 25,636 | 20,159 | 476,652 | 42.3 |
| 2009 | 26,057 | 20,624 | 493,100 | 41.8 |
| 2010 | 26,816 | 21,316 | 487,627 | 43.7 |
| 2011 | 28,479 | 22,902 | 514,637 | 44.5 |

2012 29,542 24,033 482,822 49.8

2013 29,523 24,206 484,994 49.9

2014 31,346 25,728 514,786 50.0

Source: U.S. Energy Information Administration (U.S. EIA). 2014. Natural Gas Annual 2014.

<http://www.eia.gov/naturalgas/annual/pdf/nga14.pdf>. Accessed January 22, 2016.

1 Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of

nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

Domestic exploration and development for oil has continued during the last two decades.

From 2002 to 2010, crude oil well drilling showed significant increases, although the 1992-2004

period showed relatively low levels of crude drilling activity compared to periods before and

after (Table 2-6). The drop in 2009 showed a departure from the increasing trend, likely due to

the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2010 period.

Like crude oil drilling, 2009 and 2010 saw a relatively low level of natural gas drillings. The



success rate of wells (producing wells versus dry wells) has also increased gradually over time

from 75 percent in 1990, to 86 percent in 2000, to a peak of 90 percent in 2009 (Table 2-6). The

increasing success rate reflects improvements in exploration technology, as well as technological

improvements in well drilling and completion. Similarly, average well depth has increased by an

estimated 1,227 feet during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and

Average Depth, 1990-2010

Wells Drilled

Year Crude Oil Natural Gas Dry Holes Total

Successful

Wells (%)

Average

Depth (ft)

1990 12,445 11,126 8,496 32,067 75 4,881

1991 12,035 9,611 7,882 29,528 75 4,920

1992 9,019 8,305 6,284 23,608 75 5,202

1993 8,764 10,174 6,513 25,451 75 5,442

| | | | | | | |
|---|---|---|---|---|---|---|
| 1994 | 7,001 | 9,739 | 5,515 | 22,255 | 77 | 5,795 |
| 1995 | 7,827 | 8,454 | 5,319 | 21,600 | 77 | 5,636 |
| 1996 | 8,760 | 9,539 | 5,587 | 23,886 | 79 | 5,617 |
| 1997 | 10,445 | 11,186 | 5,955 | 27,586 | 79 | 5,691 |
| 1998 | 6,979 | 11,127 | 4,805 | 22,911 | 80 | 5,755 |
| 1999 | 4,314 | 11,121 | 3,504 | 18,939 | 83 | 5,090 |
| 2000 | 8,090 | 17,051 | 4,146 | 29,287 | 86 | 4,961 |
| 2001 | 8,888 | 22,072 | 4,598 | 35,558 | 87 | 5,087 |
| 2002 | 6,775 | 17,342 | 3,754 | 27,871 | 87 | 5,232 |
| 2003 | 8,129 | 20,722 | 3,982 | 32,833 | 88 | 5,426 |
| 2004 | 8,789 | 24,186 | 4,082 | 37,057 | 89 | 5,547 |
| 2005 | 10,779 | 28,590 | 4,653 | 44,022 | 89 | 5,508 |
| 2006 | 13,385 | 32,838 | 5,206 | 51,429 | 90 | 5,613 |
| 2007 | 13,371 | 32,719 | 4,981 | 51,071 | 90 | 6,064 |
| 2008 | 16,633 | 32,246 | 5,423 | 54,302 | 90 | 5,964 |
| 2009* | 11,190 | 18,088 | 3,525 | 32,803 | 90 | 6,202 |
| 2010* | 15,753 | 16,696 | 4,162 | 36,611 | 89 | 6,108 |

Source: U.S. Energy Information Administration

* Average Depth values for 2009-2010 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging.

Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of



flowback water from hydraulic fracturing activities (ANL 2009). As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low produced water to oil ratios compared to states like Illinois, Florida, Missouri, Indiana and Kansas.



Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State

Crude Oil

(1000 bbl)

Total Gas

(bcf)

Produced Water

(1000 bbl)

Total Oil and

Natural Gas

(1000 bbls oil

equivalent)

Barrels

Produced

Water per

Barrel Oil

Equivalent

Alabama 5,028 285 119,004 55,758 2.13

Alaska 263,595 3,498 801,336 886,239 0.90

Arizona 43 1 68 221 0.31

Arkansas 6,103 272 166,011 54,519 3.05

California 244,000 312 2,552,194 299,536 8.52

Colorado 2,375 1,288 383,846 231,639 1.66

Florida 2,078 2 50,296 2,434 20.66

Illinois 3,202 no data 136,872 3,202 42.75

Indiana 1,727 4 40,200 2,439 16.48

Kansas 36,612 371 1,244,329 102,650 12.12

Kentucky 3,572 95 24,607 20,482 1.20

Louisiana 52,495 1,382 1,149,643 298,491 3.85

Michigan 5,180 168 114,580 35,084 3.27

Mississippi 20,027 97 330,730 37,293 8.87

Missouri 80 no data 1,613 80 20.16

Montana 34,749 95 182,266 51,659 3.53

Nebraska 2,335 1 49,312 2,513 19.62

Nevada 408 0 6,785 408 16.63

New Mexico 59,138 1,526 665,685 330,766 2.01

New York 378 55 649 10,168 0.06

North Dakota 44,543 71 134,991 57,181 2.36

Ohio 5,422 86 6,940 20,730 0.33

Oklahoma 60,760 1,643 2,195,180 353,214 6.21

Pennsylvania 1,537 172 3,912 32,153 0.12

South Dakota 1,665 12 4,186 3,801 1.10

Tennessee 350 1 2,263 528 4.29

Texas 342,087 6,878 7,376,913 1,566,371 4.71

Utah 19,520 385 148,579 88,050 1.69

Virginia 19 112 1,562 19,955 0.08

West Virginia 679 225 8,337 40,729 0.20

Wyoming 54,052 2,253 2,355,671 455,086 5.18

State Total 1,273,759 21,290 20,258,560 5,063,379 4.00

Federal

Offshore

467,180 2,787 587,353 963,266 0.61

Tribal Lands 9,513 297 149,261 62,379 2.39

Federal Total 476,693 3,084 736,614 1,025,645 0.72

U.S. Total 1,750,452 24,374 20,995,174 6,089,024 3.45

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

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Figure 2-3 shows the distribution of produced water management practices in 2007. More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. About one third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) was discharged into surface water when it met water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage decreased during the 1990-2010 period, appearing to follow the downward supply trend shown in Table 2-4. Since 2010, total crude oil pipeline mileage has increased by over 12,000 miles (Table 2-8).

Table 2-8 splits natural gas pipelines into four types: distribution mains, distribution service, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites and deliver it directly to gas processing plants or compression stations which connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants and distribution points. From these distribution points, the gas enters a distribution system

that delivers the gas to final consumers. Mileage on the distribution side, distribution mains and

51%

34%

3%

11%

Injection for

Enhanced Recovery

Injection or

Disposal

Surface Discharge

Unknown

Source: Argonne National Laboratory

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distribution service, has increased while transmission pipeline and gathering line mileage has

decreased. Since 2010, total natural gas pipeline has increased by over 61,000 miles.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 2010-2014

| | Natural Gas Pipelines (miles) | | | | | Crude Oil Pipelines (miles) |
|---|---|---|---|---|---|---|
| | Distribution mains | Distribution Service | Transmission pipelines | Gathering lines | Total | Total |
| 2010 | 1,229,725 | 872,466 | 304,805 | 19,626 | 2,426,622 | 54,631 |
| 2011 | 1,238,947 | 881,955 | 305,058 | 19,350 | 2,445,310 | 56,100 |
| 2012 | 1,247,231 | 890,361 | 303,341 | 16,532 | 2,457,465 | 57,463 |
| 2013 | 1,255,145 | 894,283 | 302,827 | 17,369 | 2,469,624 | 61,087 |
| 2014 | 1,266,039 | 902,772 | 301,806 | 17,621 | 2,488,238 | 66,700 |

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of

Pipeline Safety, Annual Report Mileage Summary Statistics, available at

<http://phmsa.dot.gov/pipeline/library/datastats> as of January 4, 2016.

### 2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2012 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008, when total consumption basically leveled off as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the percentage of the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2012.



Table 2-9 Crude Oil Consumption by Sector, 1990-2012

| | | Percent of Total | | | |
|---|---|---|---|---|---|
| Sector | Total (million barrels) | Residential and Commercial | Industrial | Transportation | Electric Power |
| 1990 | 6,178 | 7.3 | 25.1 | 64.3 | 3.3 |
| 1991 | 6,068 | 7.3 | 24.9 | 64.7 | 3.2 |
| 1992 | 6,209 | 7.1 | 26.1 | 64.3 | 2.6 |
| 1993 | 6,277 | 6.9 | 25.3 | 65.0 | 2.9 |
| 1994 | 6,439 | 6.6 | 26.0 | 64.8 | 2.6 |
| 1995 | 6,402 | 6.4 | 25.7 | 66.0 | 1.9 |
| 1996 | 6,627 | 6.7 | 26.1 | 65.2 | 2.0 |
| 1997 | 6,726 | 6.3 | 26.4 | 65.1 | 2.2 |
| 1998 | 6,837 | 5.7 | 25.4 | 65.8 | 3.1 |
| 1999 | 7,053 | 6.1 | 25.6 | 65.5 | 2.8 |
| 2000 | 6,984 | 4.6 | 25.1 | 67.6 | 2.6 |
| 2001 | 6,963 | 4.6 | 25.1 | 67.4 | 2.9 |
| 2002 | 6,990 | 4.2 | 25.2 | 68.3 | 2.2 |
| 2003 | 7,091 | 4.6 | 24.8 | 67.9 | 2.7 |
| 2004 | 7,399 | 4.4 | 25.3 | 67.7 | 2.6 |
| 2005 | 7,530 | 5.8 | 24.2 | 67.3 | 2.6 |

| | | | | | |
|---|---|---|---|---|---|
| 2006 | 7,506 | 5.0 | 24.8 | 68.9 | 1.4 |
| 2007 | 7,517 | 5.1 | 24.1 | 69.5 | 1.4 |
| 2008 | 7,095 | 5.5 | 23.0 | 70.4 | 1.1 |
| 2009 | 6,849 | 5.5 | 22.2 | 71.4 | 1.0 |
| 2010 | 6,994 | 5.2 | 22.8 | 71.0 | 0.9 |
| 2011 | 7,013 | 5.0 | 23.2 | 71.1 | 0.7 |
| 2012 | 6,902 | 5.0 | 23.4 | 71.1 | 0.5 |

Source: U.S. Energy Information Administration.



Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2012

Natural gas consumption has increased over the last twenty years. From 1990 to 2014, total U.S. consumption increased by an average of about 1.6 percent per year (Table 2-10 and Figure 2-5). Over this period, the percentage of natural gas consumed by the industrial sector declined, whereas the percent of total natural gas used for electric power generation increased dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential sector demand has bounced around between about 23 and 19 percent, where the lower percentage of total demand falls mainly in the years post 2008 with slightly larger dip in 2012. Commercial sector demand hovered around 13 and 14 percent, also with a slight dip in 2012. The transportation sector has maintained a fairly constant consumption level of right around 3 percent between 1990 and 2014.

0%

10%

20%

30%

40%

50%

60%

70%

80%

Consumption (% of total)

Residential and Commercial Industrial

Transportation Sector Electric Power

Table 2-10 Natural Gas Consumption by Sector, 1990-2014

| | | Percent of Total | | | | |
|---|---|---|---|---|---|---|
| | Total (tcf) | Residential | Commercial | Industrial | Electric Power | Transportation |
| 1990 | 19.17 | 22.9 | 13.7 | 43.1 | 16.9 | 3.4 |
| 1991 | 19.56 | 23.3 | 13.9 | 42.7 | 17.0 | 3.1 |
| 1992 | 20.23 | 23.2 | 13.9 | 43.0 | 17.0 | 2.9 |
| 1993 | 20.79 | 23.8 | 13.8 | 42.7 | 16.7 | 3.0 |
| 1994 | 21.25 | 22.8 | 13.6 | 42.0 | 18.4 | 3.2 |
| 1995 | 22.21 | 21.8 | 13.6 | 42.3 | 19.1 | 3.2 |
| 1996 | 22.61 | 23.2 | 14.0 | 42.8 | 16.8 | 3.2 |
| 1997 | 22.74 | 21.9 | 14.1 | 42.7 | 17.9 | 3.3 |
| 1998 | 22.25 | 20.3 | 13.5 | 42.7 | 20.6 | 2.9 |
| 1999 | 22.41 | 21.1 | 13.6 | 40.9 | 21.5 | 2.9 |
| 2000 | 23.33 | 21.4 | 13.6 | 39.8 | 22.3 | 2.8 |
| 2001 | 22.24 | 21.5 | 13.6 | 38.1 | 24.0 | 2.9 |
| 2002 | 23.03 | 21.2 | 13.7 | 37.5 | 24.6 | 3.0 |
| 2003 | 22.28 | 22.8 | 14.3 | 37.1 | 23.1 | 2.7 |
| 2004 | 22.40 | 21.7 | 14.0 | 37.3 | 24.4 | 2.6 |
| 2005 | 22.01 | 21.9 | 13.6 | 35.0 | 26.7 | 2.8 |
| 2006 | 21.70 | 20.1 | 13.1 | 35.3 | 28.7 | 2.8 |
| 2007 | 23.10 | 20.4 | 13.0 | 34.1 | 29.6 | 2.8 |
| 2008 | 23.28 | 21.0 | 13.5 | 33.9 | 28.6 | 2.9 |
| 2009 | 22.91 | 20.9 | 13.6 | 32.5 | 30.0 | 3.0 |
| 2010 | 24.09 | 19.9 | 12.9 | 33.7 | 30.7 | 2.9 |
| 2011 | 24.48 | 19.3 | 12.9 | 34.0 | 30.9 | 2.9 |
| 2012 | 25.54 | 16.2 | 11.3 | 33.8 | 35.7 | 3.0 |
| 2013 | 26.16 | 18.7 | 12.6 | 34.1 | 31.3 | 3.3 |
| 2014 | 26.69 | 19.1 | 13.0 | 34.2 | 30.5 | 3.3 |

Source: U.S. Energy Information (U.S. EIA). Monthly Energy Review. Table 4.3 Natural Gas Consumption by Sector data. <http://www.eia.gov/beta/MER/index.cfm?tbl=T04.03#/?f=A&start=1990&end=2014&charted=1-2-9-13-14>. Accessed February 3, 2016.

Note: Industrial Consumption is reported as Lease and Plant Fuel, Other Industrial: CHP, and Other Industrial: Non-CHP

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-

2012

Source: U.S. Energy Information (U.S. EIA). Monthly Energy Review. Table 4.3 Natural Gas Consumption by

Sector data. <
http://www.eia.gov/beta/MER/index.cfm?tbl=T04.03#/?f=A&start=1990&end=2014&charted=1-2-9-

13-14>. Accessed February 3, 2016.

2.4.4 International Trade

Until 2006, net trade of crude oil and refined petroleum products increased, showing

increased substitution of imports for domestic production, as well as imports satisfying growing

consumer demand in the U.S. (Table 2-11). Since then, however, imports have been declining

while exports have been rising, leading to significant declines in net trade or crude oil and

petroleum products.

0%

5%

10%

15%

20%

25%

30%

35%

40%

45%

50%

Consumption (% of total)

Residential Commercial

Industrial Electric Power

Transportation



Table 2-11 Total Crude Oil and Petroleum Products Trade (Million Bbl),

1990-2014

Imports Exports Net Imports

Crude

Oil

Petroleum

Products Total

Crude

Oil

Petroleum

Products Total

Crude

Oil

Petroleum

Products Total

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1990 | 2,151 | 775 | 2,926 | 40 | 273 | 313 | 2,112 | 502 | 2,614 |
| 1991 | 2,111 | 673 | 2,784 | 42 | 323 | 365 | 2,068 | 350 | 2,418 |
| 1992 | 2,226 | 661 | 2,887 | 32 | 315 | 348 | 2,194 | 345 | 2,539 |
| 1993 | 2,477 | 669 | 3,146 | 36 | 330 | 366 | 2,441 | 339 | 2,780 |
| 1994 | 2,578 | 706 | 3,284 | 36 | 308 | 344 | 2,542 | 398 | 2,940 |
| 1995 | 2,639 | 586 | 3,225 | 35 | 312 | 346 | 2,604 | 274 | 2,878 |
| 1996 | 2,748 | 721 | 3,469 | 40 | 319 | 359 | 2,708 | 403 | 3,110 |
| 1997 | 3,002 | 707 | 3,709 | 39 | 327 | 366 | 2,963 | 380 | 3,343 |
| 1998 | 3,178 | 731 | 3,908 | 40 | 305 | 345 | 3,137 | 426 | 3,564 |
| 1999 | 3,187 | 774 | 3,961 | 43 | 300 | 343 | 3,144 | 474 | 3,618 |
| 2000 | 3,320 | 874 | 4,194 | 18 | 362 | 381 | 3,301 | 512 | 3,813 |
| 2001 | 3,405 | 928 | 4,333 | 7 | 347 | 354 | 3,398 | 581 | 3,979 |
| 2002 | 3,336 | 872 | 4,209 | 3 | 356 | 359 | 3,333 | 517 | 3,849 |
| 2003 | 3,528 | 949 | 4,477 | 5 | 370 | 375 | 3,523 | 579 | 4,102 |
| 2004 | 3,692 | 1119 | 4,811 | 10 | 374 | 384 | 3,682 | 745 | 4,427 |
| 2005 | 3,696 | 1310 | 5,006 | 12 | 414 | 425 | 3,684 | 896 | 4,580 |
| 2006 | 3,693 | 1310 | 5,003 | 9 | 472 | 481 | 3,684 | 838 | 4,523 |
| 2007 | 3,661 | 1255 | 4,916 | 10 | 513 | 523 | 3,651 | 742 | 4,393 |
| 2008 | 3,581 | 1146 | 4,727 | 10 | 649 | 659 | 3,570 | 497 | 4,068 |
| 2009 | 3,290 | 977 | 4,267 | 16 | 723 | 739 | 3,274 | 255 | 3,528 |
| 2010 | 3,363 | 942 | 4,305 | 15 | 843 | 859 | 3,348 | 98 | 3,446 |
| 2011 | 3,261 | 913 | 4,174 | 17 | 1073 | 1,090 | 3,244 | -160 | 3,084 |
| 2012 | 3,121 | 758 | 3,879 | 25 | 1148 | 1,173 | 3,096 | -390 | 2,706 |
| 2013 | 2,821 | 777 | 3,598 | 49 | 1273 | 1,322 | 2,773 | -496 | 2,277 |
| 2014 | 2,681 | 692 | 3,373 | 128 | 1396 | 1,524 | 2,552 | -704 | 1,849 |

Sources: U.S. Energy Information Administration (U.S. EIA). U.S. Imports by Country of Origin.

<http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbbl_a.htm>. Accessed January 22, 2016.

U.S. Energy Information Administration (U.S. EIA). U.S. Exports by Destination.

<https://www.eia.gov/dnav/pet/pet_move_expc_a_EP00_EEX_mbbl_a.htm>. Accessed January 22, 2016.

From 1990 to 2007, natural gas imports have increased steadily in both volume and percentage terms (Table 2-12). Imported natural gas constituted a lower percentage of domestic

natural gas consumption from 2007 through 2014 compared to earlier years. Until recent years,

industry analysts have forecasted that LNG imports would continue to grow as a percentage of

U.S. consumption. However, it is possible that increasingly accessible domestic unconventional

gas resources, such as shale gas and coalbed methane, is reducing the need for the U.S. to import

natural gas, either via pipeline or shipped LNG.



Table 2-12 Natural Gas Imports and Exports, 1990-2014

| | Total Imports (bcf) | Total Exports (bcf) | Net Imports (bcf) | Percent of U.S. Consumption |
|---|---|---|---|---|
| 1990 | 1,532 | 86 | 1,447 | 7.5 |
| 1991 | 1,773 | 129 | 1,644 | 8.4 |
| 1992 | 2,138 | 216 | 1,921 | 9.5 |
| 1993 | 2,350 | 140 | 2,210 | 10.6 |
| 1994 | 2,624 | 162 | 2,462 | 11.6 |
| 1995 | 2,841 | 154 | 2,687 | 12.1 |
| 1996 | 2,937 | 153 | 2,784 | 12.3 |
| 1997 | 2,994 | 157 | 2,837 | 12.4 |
| 1998 | 3,152 | 159 | 2,993 | 13.4 |
| 1999 | 3,586 | 163 | 3,422 | 15.3 |
| 2000 | 3,782 | 244 | 3,538 | 15.2 |
| 2001 | 3,977 | 373 | 3,604 | 16.2 |
| 2002 | 4,015 | 516 | 3,499 | 15.2 |
| 2003 | 3,944 | 680 | 3,264 | 14.8 |
| 2004 | 4,259 | 854 | 3,404 | 15.5 |
| 2005 | 4,341 | 729 | 3,612 | 16.7 |
| 2006 | 4,186 | 724 | 3,462 | 16.2 |
| 2007 | 4,608 | 822 | 3,785 | 16.6 |
| 2008 | 3,984 | 963 | 3,021 | 13.2 |
| 2009 | 3,751 | 1,072 | 2,679 | 11.7 |
| 2010 | 3,741 | 1,137 | 2,604 | 10.8 |

| | | | | |
|---|---|---|---|---|
| 2011 | 3,468 | 1,506 | 1,962 | 8.0 |
| 2012 | 3,138 | 1,619 | 1,519 | 5.9 |
| 2013 | 2,883 | 1,572 | 1,311 | 5.0% |
| 2014 | 2,695 | 1,514 | 1,181 | 4.4% |

Source: U.S. Energy Information Administration (U.S. EIA). U.S. Natural Gas Imports & Exports by State.

<https://www.eia.gov/dnav/ng/NG_MOVE_STATE_DCU_NUS_A.htm>. Accessed January 21, 2016.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the most current forecast information available from the EIA, the 2014 and 2015 Annual Energy Outlook. The 2014 and 2015 Annual Energy Outlook was produced using the National Energy Modeling System (NEMS), which the EPA uses to analyze the impacts of the final NSPS on the national economy as is discussed in detail in Section 7.

Table 2-13 present forecasts of successful wells drilled in the U.S. from 2010 to 2040.

Crude oil well forecasts for the lower 48 states show a rise up to the year 2025 then a gradual



decline until 2040. Meanwhile, the forecast shows an increase in natural gas drilling in the lower 48 states from the present to 2040, more than doubling during this 25-year period.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2040

| | Totals | |
|---|---|---|
| Year | Crude Oil | Natural Gas |
| 2010 | 19,316 | 19,056 |
| 2011 | 23,048 | 14,355 |
| 2012 | 26,749 | 11,011 |
| 2013 | 25,248 | 11,507 |
| 2014 | 22,274 | 14,099 |
| 2015 | 22,706 | 14,076 |
| 2016 | 22,552 | 15,004 |
| 2017 | 22,355 | 15,773 |
| 2018 | 22,421 | 18,340 |
| 2019 | 22,525 | 20,188 |
| 2020 | 24,765 | 20,396 |
| 2021 | 25,017 | 23,427 |
| 2022 | 25,400 | 24,945 |
| 2023 | 25,981 | 24,999 |

| | | |
|---|---|---|
| 2024 | 26,917 | 24,745 |
| 2025 | 27,763 | 24,831 |
| 2026 | 26,258 | 25,445 |
| 2027 | 25,830 | 26,895 |
| 2028 | 25,270 | 28,341 |
| 2029 | 24,801 | 29,019 |
| 2030 | 24,310 | 28,799 |
| 2031 | 23,972 | 29,681 |
| 2032 | 23,607 | 31,406 |
| 2033 | 23,283 | 31,749 |
| 2034 | 23,057 | 32,882 |
| 2035 | 22,740 | 33,278 |
| 2036 | 22,494 | 33,456 |
| 2037 | 22,343 | 33,536 |
| 2038 | 22,075 | 33,944 |
| 2039 | 21,911 | 34,001 |
| 2040 | 21,750 | 33,656 |

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014.

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and

Figure 2-6 depicts these trends graphically. Table 2-14 also shows forecasts of proved reserves in

the lower 48 states. The reserves forecast shows steady growth from 2012 to 2040, with an

increase of 49 percent overall. This increment is smaller than the forecast increase in production

from the lower 48 states during this period, 52 percent, showing production is forecast to grow



more rapidly than reserves. In addition, Table 2-14 shows average wellhead prices increasing

more than 41 percent from 2012 to 2040, from $96.38 per barrel to $136.13 per barrel in 2013

dollar terms.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2012-2040

Domestic Production (million bbls)

Total

Domestic

Lower

48

Onshore

Lower

48

Offshore Alaska

Other

Crude

Supply

Net

Imports

Total

Crude

Supply

Lower

48 End

of Year

Reserves

(million

bbls)

Lower 48

Average

Wellhead

Price (2013

dollars per

barrel)

2012 2,373 1,678 503 192 16 3,088 5,476 30,051 96.38

2013 2,715 2,032 495 188 97 2,773 5,584 29,441 96.51

2014 3,151 2,422 549 180 47 2,563 5,761 31,131 90.37

2015 3,404 2,640 599 164 78 2,343 5,826 31,966 53.49

2016 3,486 2,691 637 158 51 2,307 5,845 33,549 68.35

2017 3,651 2,790 699 162 0 2,156 5,807 34,747 72.44

2018 3,786 2,865 757 164 0 2,055 5,841 35,948 72.34

2019 3,861 2,906 797 158 0 1,995 5,857 37,002 73.79

2020 3,870 2,933 785 153 0 2,012 5,882 37,403 75.16

2021 3,837 2,923 770 145 0 2,086 5,924 37,760 76.97

2022 3,812 2,918 757 137 0 2,131 5,943 38,137 79.27

2023 3,785 2,918 738 129 0 2,181 5,966 38,605 81.68

2024 3,786 2,932 732 122 0 2,189 5,975 39,066 84.11

2025 3,752 2,924 712 116 0 2,222 5,974 39,389 86.57

2026 3,692 2,869 712 110 0 2,285 5,977 39,908 89.27

2027 3,682 2,850 729 103 0 2,300 5,982 40,633 92.03

2028 3,700 2,837 766 97 0 2,291 5,991 41,497 94.89

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2029 | 3,681 | 2,802 | 787 | 92 | 0 | 2,321 | 6,002 | 42,109 | 97.86 |
| 2030 | 3,665 | 2,773 | 805 | 86 | 0 | 2,349 | 6,014 | 42,593 | 100.92 |
| 2031 | 3,573 | 2,688 | 804 | 82 | 0 | 2,454 | 6,027 | 42,708 | 104.19 |
| 2032 | 3,495 | 2,622 | 795 | 77 | 0 | 2,533 | 6,028 | 42,665 | 107.44 |
| 2033 | 3,448 | 2,587 | 787 | 73 | 0 | 2,604 | 6,052 | 42,795 | 110.82 |
| 2034 | 3,424 | 2,578 | 777 | 69 | 0 | 2,657 | 6,081 | 43,066 | 113.86 |
| 2035 | 3,425 | 2,580 | 780 | 66 | 0 | 2,683 | 6,108 | 43,425 | 117.20 |
| 2036 | 3,407 | 2,571 | 773 | 62 | 0 | 2,723 | 6,130 | 43,609 | 120.77 |
| 2037 | 3,404 | 2,557 | 766 | 81 | 0 | 2,752 | 6,156 | 43,808 | 124.33 |
| 2038 | 3,422 | 2,541 | 774 | 107 | 0 | 2,748 | 6,170 | 44,124 | 128.36 |
| 2039 | 3,420 | 2,534 | 761 | 126 | 0 | 2,766 | 6,187 | 44,234 | 132.37 |
| 2040 | 3,440 | 2,527 | 790 | 123 | 0 | 2,768 | 6,208 | 44,779 | 136.13 |

Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with Projections to

2040. < http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf>. Accessed January 25, 2016.

2-30

Figure 2-6 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2040

Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with

Projections to 2040. < http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf>. Accessed January 25, 2016.

Table 2-15 shows domestic natural gas production is forecast to increase until 2040.

Meanwhile, imports of natural gas via pipeline are eliminated during the forecast period, from

1.37 tcf in 2012 to -2.33 tcf in 2040. Imports of LNG are also expected to be eliminated during

the forecast period, from 0.15 tcf in 2012 to -3.29 tcf in 2040. Dry Gas Production increases

about 47 percent, from 24.06 tcf in 2012 to 35.45 in 2040. Total supply increases about 17

percent, from 25.64 tcf in 2012 to 29.90 tcf in 2040.

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Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

2012-2040

Domestic Production (tcf) Net Imports (tcf)

Dry Gas

Production

Supplemental

Natural Gas

Net

Imports

(Pipeline)

Net

Imports

(LNG)

Total

Supply

Lower 48

End of

Year Dry

Reserves

(tcf)

Average Henry

Hub Spot Price

(2013 dollars

per million

Btu)

2012 24.06 0.06 1.37 0.15 25.64 298.5 2.79

2013 24.40 0.05 1.20 0.09 25.75 293.2 3.73

2014 25.57 0.06 1.09 0.05 26.77 299.0 4.37

2015 26.43 0.06 0.83 -0.03 27.29 300.8 3.69

2016 27.30 0.06 0.58 -0.23 27.71 301.5 3.70

2017 27.18 0.06 0.23 -0.69 26.78 303.7 3.80

2018 27.68 0.06 -0.07 -1.05 26.62 305.5 4.21

2019 28.27 0.06 -0.29 -1.52 26.53 307.5 4.55

2020 28.82 0.06 -0.48 -2.08 26.33 308.9 4.88

2021 29.17 0.06 -0.58 -2.37 26.28 310.6 5.02

2022 29.53 0.06 -0.72 -2.49 26.39 312.1 5.09

2023 29.85 0.06 -0.83 -2.49 26.60 313.3 5.25

2024 30.17 0.06 -0.91 -2.49 26.84 314.7 5.35

2025 30.51 0.06 -1.01 -2.49 27.07 315.7 5.46

2026 30.78 0.06 -1.09 -2.49 27.27 316.8 5.67

2027 31.37 0.06 -1.21 -2.69 27.54 319.2 5.67

2028 31.94 0.06 -1.31 -2.89 27.80 322.2 5.67

2029 32.50 0.06 -1.41 -3.09 28.06 325.3 5.71

2030 33.01 0.06 -1.52 -3.29 28.27 328.7 5.69

2031 33.19 0.06 -1.60 -3.29 28.37 330.8 5.91

2032 33.40 0.06 -1.69 -3.29 28.49 332.7 6.09

2033 33.63 0.06 -1.77 -3.29 28.63 334.5 6.27

2034 33.84 0.06 -1.83 -3.29 28.79 336.5 6.45

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2035 | 34.14 | 0.06 | -1.90 | -3.29 | 29.01 | 338.3 | 6.60 |
| 2036 | 34.46 | 0.06 | -2.00 | -3.29 | 29.24 | 339.9 | 6.76 |
| 2037 | 34.75 | 0.06 | -2.09 | -3.29 | 29.44 | 341.5 | 6.84 |
| 2038 | 35.04 | 0.06 | -2.19 | -3.29 | 29.62 | 343.3 | 7.02 |
| 2039 | 35.28 | 0.06 | -2.30 | -3.29 | 29.75 | 344.3 | 7.38 |
| 2040 | 35.45 | 0.06 | -2.33 | -3.29 | 29.90 | 345.2 | 7.85 |

Source: U.S. Energy Information Administration (U.S. EIA). April 2015. Annual Energy Outlook 2015 with

Projections to 2040. < http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf>. Accessed January 19, 2016

2-32

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past

two decades, particularly in recent years. Cost per well has increased by an annual average of

about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure

2-7).

Figure 2-7 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by the EIA add an additional level of

detail to drilling costs, in that finding costs incorporate the broader costs associated with adding

proved reserves of crude oil and natural gas. These costs include exploration and development

costs, as well as costs associated with the purchase or leasing of real property. The EIA publishes

finding costs as running three-year averages, in order to better compare these costs, which occur

over several years, with annual average lifting costs. Figure 2-8 shows average domestic

onshore, offshore and foreign finding costs for the sample of U.S. firms in the EIA's Financial

Reporting System (FRS) database from 1981 to 2009. The costs are reported in 2009 dollars on a

barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic

0

500,000

1,000,000

1,500,000

2,000,000

2,500,000

3,000,000

3,500,000

4,000,000

4,500,000

5,000,000

1981 1984 1987 1990 1993 1996 1999 2002 2005 2008

Drilling Costs Per Well ($2005)

0

100

200

300

400

500

600

700

800

Drilling Costs Per Foot ($2005)

Dollars per Well (2005 dollars) Dollars per Foot (2005 dollars)



finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore, offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore, offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-7 and finding costs in Figure 2-8 present similar trends overall.

Figure 2-8 Finding Costs for FRS Companies, 1981-2009

Source: U.S. Energy Information Administration (U.S. EIA). February 2011. Performance Profiles of Major Energy Producers, 2009.Figure 17 data. <http://www.eia.gov/finance/performanceprofiles/oil_gas.cfm>. Accessed January 19, 2016.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. The EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, the

EIA reports average lifting costs for FRS firms in 2009 dollars on a barrel of oil equivalent basis.

0

10

20

30

40

50

60

70

80

$2008/boe

U.S. Onshore U.S. Offshore Foreign



Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-9 depicts

direct lifting cost trends from 1981 to 2009 for domestic and foreign production.

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little

more than $2 per barrel of oil equivalent between 1981 and 1985, then declined almost $5 per

barrel of oil equivalent by 2000. From 2000 to 2009, domestic lifting costs increased sharply,

just over $8 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs

from 1981 to 1991, with foreign lifting costs lower than domestic costs during this period. After

1991, foreign and domestic lifting costs followed a similar track until they again diverged in

2004, with domestic lifting again becoming more expensive. Combined with finding costs, the

total finding and lifting costs rose significantly in from 2000 to 2009.

Figure 2-9 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2009 (3-

year Running Average)

Source: U.S. Energy Information Administration (U.S. EIA). February 2011. Performance Profiles of Major Energy

Producers, 2009.Figure 15 data. <http://www.eia.gov/finance/performanceprofiles/oil_gas.cfm>. Accessed January

19, 2016.

0

2

4

6

8

10

12

14

$2008/boe

Domestic Foreign



### 2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[8], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-10 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, but operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s. Oil costs and prices again generally rose between 2000 and 2009, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

8 U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.



Figure 2-10 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-20099

Source: U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010.

<http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipmen

t_production/current/cos

tstudy.html> Accessed February 2, 2011.

Figure 2-11 depicts natural gas operating and equipment costs indices, as well as natural

gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs

track the price of natural gas over this time period, while operating costs have risen more quickly

than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late

1970s, but generally decreased from about 1980 until the mid-1990s. The 2009 index values for

natural gas operating and equipment costs are 137 and 112, respectively.

9 The last release date for the EIA's Oil and Gas Lease Equipment and Operating Costs analysis was September

2010. Updates have been discontinued.

0

20

40

60

80

100

120

140

160

180

200

1976 1979 1982 1985 1988 1991 1994 1997 2000 2003 2006 2009

Cost Index (1976=100)

0

5

10

15

20

25

30

35

40

45

50

Oil Price ($/bbl, 1976 Dollars)

Crude Oil Operating Costs

Crude Oil Equipment Cost Index

Crude Oil Price ($/bbl, 1976 Dollars)



Figure 2-11 Natural Operating Costs and Equipment Costs Indices (1976=100) and

Natural Gas Price, 1976-2009

Source: U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through

2009." September 28, 2010.

<http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/cos

tstudy.html> Accessed February 2, 2011.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and

natural gas will potentially affect the business entities that own the regulated facilities. In the oil

and natural gas production industry, facilities comprise those sites where plants and equipment

extract, process, and transport extracted streams recovered from the raw crude oil and natural gas

resources. Companies that own these facilities are legal business entities that have the capacity to

conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that

include producers, transporters, and distributors. The producer segment may be further divided

between major and independent producers. Major producers include large oil and gas companies

that are involved in each of the five industry segments: drilling and exploration, production,

0

20

40

60

80

100

120

140

160

1976 1979 1982 1985 1988 1991 1994 1997 2000 2003 2006 2009

Cost Index (1976=100)

0

1

1

2

2

3

3

4

4

5

5

Natural Gas Price ($/MMcf, 1976 Dollars)

Natural Gas Operating Costs

Natural Gas Equipment Costs

Natural Gas Price ($/Mcf, 1976 Dollars)



transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 54 percent of domestic crude oil, 85 percent of domestic natural gas, and drill almost 95 percent of the wells in the U.S (IPAA, 2012-13). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected NAICS

As of 2012, there were 6,679 firms within the 211111 and 211112 NAICS codes, of which 6,551 (98 percent) were considered small entities (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for almost 61 percent of employment listed under these NAICS. The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 56 percent of employment. Within NAICS 486210, large firms compose about 43 percent of total firms and about 95 percent of employment.

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Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

| NAICS | NAICS Description | SBA Size Standard** (Employees or Annual Receipts) | *Small Firms | *Large Firms | *Total Firms |
|---|---|---|---|---|---|
| Number of Firms by Firm Size | | | | | |
| 211111 | Crude Petroleum and Natural Gas Extraction | 500[1] | 6,444 | 92 | 6,536 |
| 211112 | Natural Gas Liquid Extraction | 500[2] | 107 | 36 | 143 |
| 213111 | Drilling Oil and Gas Wells | 500[3] | 2,085 | 59 | 2,144 |
| 213112 | Support Activities for Oil and Gas Operations | $38.5 million | 8,750 | 127 | 8,877 |
| 486210 | Pipeline Transportation of Natural Gas | $27.5 million | 92 | 46 | 138 |
| Total Employment by Firm Size | | | | | |
| 211111 | Crude Petroleum and Natural Gas Extraction | 500 | 47,528 | 66,996 | 114,524 |
| 211112 | Natural Gas Liquid Extraction | 500 | 1,709 | 8,768 | 10,477 |
| 213111 | Drilling Oil and Gas Wells | 500 | 39,628 | 66,740 | 106,368 |
| 213112 | Support Activities for Oil and Gas Operations | $38.5 million | 126,523 | 145,834 | 272,357 |
| 486210 | Pipeline Transportation of Natural Gas | $27.5 million | 1,503 | 31,823 | 33,326 |

*These numbers are reported by Enterprise Employment Size <500 and 500+

Sources: U.S. Census Bureau. Statistics of U.S. Businesses. Accessed January 18, 2016.

U.S. Government Publishing Office. Electronic Code of Regulation, Title 13, Chapter 1, Part 121. Accessed January 18, 2016.

U.S. Small Business Administration, Office of Advocacy. 2014. Firm Size Data. Accessed January 5, 2016.

**The SBA size standards for some of the NAICS were updated in February, 2016.

1. Updated to 1,250 employees
2. Updated to 750 employees
3. Updated to 1,000 employees.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2014. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of about 314,000 in 1999, but rebounding to a 2014 peak of about 660,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.



Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-2014

Crude
Petroleum
and Natural
Gas
Extraction
(NAICS
211111)
Natural
Gas
Liquid
Extraction
(NAICS
211112)
Drilling of
Oil and
Natural Gas
Wells
(NAICS
213111)
Support
Activities
for Oil and
Gas Ops.
(NAICS
213112)
Pipeline
Trans. of
Crude Oil
(NAICS

486110)

Pipeline

Trans. of

Natural Gas

(NAICS

486210) Total

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1990 | 182,848 | 8,260 | 52,365 | 109,497 | 11,112 | 47,533 | 411,615 |
| 1991 | 177,803 | 8,443 | 46,466 | 116,170 | 11,822 | 48,643 | 409,347 |
| 1992 | 169,615 | 8,819 | 39,900 | 99,924 | 11,656 | 46,226 | 376,140 |
| 1993 | 159,219 | 7,799 | 42,485 | 102,840 | 11,264 | 43,351 | 366,958 |
| 1994 | 150,598 | 7,373 | 44,014 | 105,304 | 10,342 | 41,931 | 359,562 |
| 1995 | 142,971 | 6,845 | 43,114 | 104,178 | 9,703 | 40,486 | 347,297 |
| 1996 | 139,016 | 6,654 | 46,150 | 107,889 | 9,231 | 37,519 | 346,459 |
| 1997 | 137,667 | 6,644 | 55,248 | 117,460 | 9,097 | 35,698 | 361,814 |
| 1998 | 133,137 | 6,379 | 53,943 | 122,942 | 8,494 | 33,861 | 358,756 |
| 1999 | 124,296 | 5,474 | 41,868 | 101,694 | 7,761 | 32,610 | 313,703 |
| 2000 | 117,175 | 5,091 | 52,207 | 108,087 | 7,657 | 32,374 | 322,591 |
| 2001 | 119,099 | 4,500 | 62,012 | 123,420 | 7,818 | 33,620 | 350,469 |
| 2002 | 116,559 | 4,565 | 48,596 | 120,536 | 7,447 | 31,556 | 329,259 |
| 2003 | 115,636 | 4,691 | 51,526 | 120,992 | 7,278 | 29,684 | 329,807 |
| 2004 | 117,060 | 4,285 | 57,332 | 128,185 | 7,073 | 27,340 | 341,275 |
| 2005 | 121,535 | 4,283 | 66,691 | 145,725 | 6,945 | 27,341 | 372,520 |
| 2006 | 130,188 | 4,670 | 79,818 | 171,127 | 7,202 | 27,685 | 420,690 |
| 2007 | 141,239 | 4,842 | 84,525 | 197,100 | 7,975 | 27,431 | 463,112 |
| 2008 | 154,898 | 5,183 | 92,640 | 223,635 | 8,369 | 27,080 | 511,805 |
| 2009 | 155,150 | 5,538 | 67,756 | 193,589 | 8,753 | 26,753 | 457,539 |
| 2010 | 153,490 | 4,833 | 74,491 | 201,685 | 8,893 | 26,708 | 470,100 |
| 2011 | 164,900 | 5,835 | 87,272 | 241,490 | 8,959 | 27,320 | 535,776 |
| 2012 | 181,473 | 6,529 | 92,340 | 282,447 | 9,348 | 27,595 | 599,732 |
| 2013 | 189,804 | 6,928 | 93,261 | 296,891 | 10,059 | 26,981 | 623,924 |
| 2014 | 189,222 | 7,482 | 98,208 | 326,353 | 10,708 | 28,242 | 660,215 |

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2014 ,

<http://data.bls.gov/cgi-bin/dsrv>. Accessed on January 19, 2016.

From 1990 to 2014, average wages for the oil and natural gas industry have increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2014 for the NAICS codes associated with the oil and natural gas industry. Employees in the NAICS 211 codes earn the highest average wages in the oil and natural gas industry, while employees in the NAICS 213 codes have relatively lower wages. Average wages in natural gas pipeline transportation

show
the highest variation.

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Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2014 (2012 dollars)

| | Crude Petroleum and Natural Gas Extraction (211111) | Natural Gas Liquid Extraction (211112) | Drilling of Oil and Natural Gas Wells (213111) | Support Activities for Oil and Gas Ops. (213112) | Pipeline Trans. of Crude Oil (486110) | Pipeline Trans. of Natural Gas (486210) | Total |
|---|---|---|---|---|---|---|---|
| 1990 | 74,510 | 69,910 | 44,213 | 48,033 | 71,265 | 64,482 | 62,274 |
| 1991 | 76,016 | 70,026 | 45,614 | 49,601 | 72,311 | 68,260 | 63,916 |
| 1992 | 80,259 | 72,319 | 45,704 | 51,379 | 77,977 | 70,505 | 67,466 |
| 1993 | 81,252 | 72,271 | 47,508 | 52,674 | 76,481 | 70,810 | 67,765 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1994 | 83,014 | 74,311 | 46,739 | 52,590 | 79,827 | 71,838 | 68,090 |
| 1995 | 85,381 | 70,906 | 48,485 | 53,319 | 82,756 | 75,453 | 69,667 |
| 1996 | 88,360 | 72,290 | 51,280 | 55,426 | 80,627 | 80,141 | 71,760 |
| 1997 | 94,353 | 83,408 | 54,780 | 58,370 | 82,343 | 86,898 | 75,390 |
| 1998 | 97,915 | 94,471 | 55,718 | 60,473 | 83,066 | 88,409 | 77,429 |
| 1999 | 103,283 | 93,896 | 57,242 | 62,786 | 86,666 | 99,165 | 83,007 |
| 2000 | 115,071 | 117,532 | 63,817 | 63,535 | 85,034 | 136,971 | 91,032 |
| 2001 | 116,471 | 116,567 | 64,822 | 64,328 | 87,404 | 128,302 | 89,458 |
| 2002 | 115,367 | 108,753 | 65,257 | 62,876 | 91,806 | 96,055 | 86,280 |
| 2003 | 116,216 | 118,377 | 64,125 | 64,398 | 91,831 | 96,154 | 86,755 |
| 2004 | 127,383 | 124,432 | 66,282 | 65,703 | 98,426 | 98,531 | 91,002 |
| 2005 | 133,983 | 134,481 | 74,521 | 70,786 | 96,951 | 95,061 | 95,074 |
| 2006 | 145,726 | 140,751 | 78,083 | 74,119 | 96,738 | 104,104 | 100,131 |
| 2007 | 143,333 | 140,394 | 86,745 | 76,134 | 101,563 | 111,528 | 101,771 |
| 2008 | 153,226 | 132,644 | 86,886 | 78,468 | 107,886 | 105,176 | 105,060 |
| 2009 | 141,818 | 131,569 | 85,894 | 74,614 | 106,237 | 106,647 | 102,241 |
| 2010 | 152,145 | 132,041 | 86,337 | 77,810 | 108,906 | 112,910 | 106,572 |
| 2011 | 156,107 | 120,995 | 91,928 | 81,479 | 114,764 | 116,320 | 108,914 |
| 2012 | 155,735 | 136,353 | 92,266 | 80,222 | 120,292 | 139,127 | 108,872 |
| 2013 | 152,884 | 122,618 | 92,610 | 80,405 | 116,055 | 116,460 | 106,881 |
| 2014 | 157,827 | 123,305 | 95,454 | 83,364 | 109,590 | 116,679 | 108,807 |

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2014, annual wages per employee <http://www.bls.gov/cew/>. Accessed on January 21, 2016.

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firmlevel impacts because the regulation could affect a vertically integrated firm on more than one



level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasingly performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms. Typically, wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independent firms have to rely solely on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas productionrelated engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated.

Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual Oil and Gas Journal (OGJ) survey, the OGJ150, reports financial and operating results for public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, though now it has been reduced to the top 150. In 2014, 143 public companies are listed; in 2013 there were 139 firms.10 The 2012 list contains four companies that were not on the list in the previous year. Table 2-19 lists selected statistics for the top 20 companies in 2014. The results presented in the table reflect a decline in U.S. oil prices.

Net income for the top 134 companies fell about 17.5% between 2013 and 2014 to about $74 billion. Revenues for these companies increased by about $6 billion from 2013 to 2014, reaching $920.5 billion. Even though net revenue decreased in 2014, companies continued to invest. Capital and exploratory spending for the companies in 2014 totaled $226.4 billion, up 9.3% from 2013.

The total worldwide liquids production for the 143 firms increased 8.41 percent 3.32 billion bbl, while total worldwide gas production increased 0.54 percent to a total of 17 tcf (Oil and Gas Journal, September 7, 2015). Meanwhile, the firms increased both oil and natural gas production and reserves from 2013 to 2014. Domestic production of liquids increased about 16.73 percent from 2013 to 1.97 billion bbl, and domestic natural gas production was up about 3.95 percent to 12.4 tcf in 2014. US liquids reserves from the OGJ150 firms increased by 9.85% up to 25.53 billion bbl, and US natural gas reserves increased by 8.56% to 172.92 tcf. For context, the OGJ150 domestic crude production represents about 62 percent of total domestic production (3.18 billion bbl, according to EIA) in 2014. The OGJ150 natural gas production represents about 48 percent of total domestic production (31.3 tcf, according to EIA) in 2014.

10 Oil and Gas Journal. "OGJ150 Earnings Down as US Production Climbs." September 2, 2013.



Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2012

Worldwide

Production

US

Production

Rank by

Total

Assets Company Employees

Total

Assets

($Million)

Total

Revenue

($Million)

Net

Income

($Million)

Liquids

(Million

bbl)

Natural

Gas

(Bcf)

Liquids

(Million

bbl)

Natural

Gas

(Bcf)

Net

Wells

Drilled

1 ExxonMobil Corp. 75,300 349,493 411,939 33615 631 2,645 111 1,346 732

2 Chevron Corp. 64,700 266,026 211,970 19310 508 1,744 166 456 1125

3 ConocoPhillips 19,100 116,539 55,517 6938 270 1,443 172 679 492

4 Anadarko Petroleum Corp. 6,100 61,689 18,470 -1563 154 951 118 951 854.6

5 Occidental Petroleum Corp. 11,700 56,259 21,947 630 163 331 87 173 478.8

6 Apache Corp. 4,950 55,952 13,851 -5060 142.2 580 70.25 215.8 816.5

7 Devon Energy Corp. 6,600 50,637 19,566 1691 129 701 67 660 481

8 Chesapeake Energy Corp. 5,500 40,751 20,951 2056 75.4 1095 75.4 1095 682

9 Hess Corp. 3,045 38,578 11,439 2374 89 197 54 66 211

10 Marathon Oil Corp. 3,330 36,011 11,258 3046 118 295 68 113 666

11 EOG Resources Inc. 3,000 34,763 18,035 2915 134.7 506.3 132 348.4 869

12 Noble Energy Inc. 2,735 22,553 5,101 1214 49 362 32 189 324.4

13 Freeport-McMoRan Inc. 35,000 20,834 4,710 -4479 43 82 43 82 210

14 Murphy Oil Corp. 1,712 16,742 5,476 906 55.4 162.8 25 32.3 189

15 Linn Energy LLC 1,800 16,424 4,983 -452 38.8 209 38.8 209 699

16 Continental Resources Inc. 300 15,145 4,802 977 44.53 114 44.53 114 388.5

17 Pioneer Natural Resources Co. 4,075 14,926 5,055 930 48.48 154.4 48.48 154.4 502

18 Southwestern Energy Corp. 2,781 14,925 4,038 924 0.466 765 0.466 765 221

19 Whiting Petroleum Corp. 1282 14,020 3,085 65 36.77 30.22 36.77 30.22 257.1

20 Denbury Resources Corp. 1,523 12,728 2,435 635 25.77 8.379 25.77 8.379 55.9

Source: Oil and Gas Journal. "OGJ150" September 7, 2015. The annual Oil and Gas Journal (OGJ) survey, the OGJ150, reports financial and operating

results for public oil and natural gas companies with domestic reserves and headquarters in the U.S.

Notes: The source for employment figures is Hoovers, a D&B Company. (Data accessed on January 20, 2016. Employee numbers are for 2014)



The OGJ also releases a period report entitled "Worldwide Gas Processing Survey",

which provides a wide range of information on existing processing facilities. We used a recent

list of U.S. gas processing facilities (Oil and Gas Journal, June 7, 2010) and other resources,

such as the American Business Directory and company websites, to best identify the parent

company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a

processing capacity of 73,767 million cubic feet per day and throughput of 45,472 million cubic

feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but

larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million

cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration,

with large firms owning multiple facilities, which also tend to be relatively large (Table 2-20).

While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total

throughput) own 264, or 46 percent, of the facilities. That larger companies tend to own larger

facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent

of actual throughput.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

| Rank | Company | Processing Plants (No.) | Natural Gas Capacity (MMcf/day) | Natural Gas Throughput (MMcf/day) |
|---|---|---|---|---|
| 1 | BP PLC | 19 | 13,378 | 11,420 |
| 2 | DCP Midstream Inc. | 64 | 9,292 | 5,586 |
| 3 | Enterprise Products Operating LP- | 23 | 10,883 | 5,347 |
| 4 | Targa Resources | 16 | 4,501 | 2,565 |
| 5 | Enbridge Energy Partners LP- | 19 | 3,646 | 2,444 |
| 6 | Williams Cos. | 10 | 4,826 | 2,347 |
| 7 | Martin Midstream Partners | 16 | 3,384 | 2,092 |
| 8 | Chevron Corp. | 23 | 1,492 | 1,041 |
| 9 | Devon Gas Services LP | 6 | 1,038 | 846 |
| 10 | ExxonMobil Corp. | 6 | 1,238 | 766 |
| 11 | Occidental Petroleum Corp | 7 | 776 | 750 |
| 12 | Kinder Morgan Energy Partners | 9 | 1,318 | 743 |
| 13 | Enogex Products Corp. | 8 | 863 | 666 |
| 14 | Hess Corp. | 3 | 1,060 | 613 |
| 15 | Norcen Explorer | 1 | 600 | 500 |
| 16 | Copano Energy | 1 | 700 | 495 |
| 17 | Anadarko | 18 | 816 | 489 |
| 18 | Oneok Field Services | 10 | 1,751 | 472 |
| 19 | Shell | 4 | 801 | 446 |
| 20 | DTE Energy | 1 | 800 | 400 |
| | TOTAL FOR TOP 20 | 264 | 63,163 | 40,028 |
| | TOTAL FOR ALL COMPANIES | 579 | 73,767 | 45,472 |

Source: Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 165 companies in 2014 (Oil and Gas Journal. September 7, 2015, "Gas Pipeline Table," pp. 126-128). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2014. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of Top 20 pipeline companies and the Top 20 firms from the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional markets.

The top 20 companies maintain about 58 percent of the total pipeline mileage and transport about 52 percent of the total volume of the industry (Table 2-21). Operating revenues



of the top 20 companies equaled $13.2 billion, representing 54 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 69 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2014

| Rank | Company | Transmission (miles) | Vol. trans for others (MMcf) | Operating Revenue ($000s) | Net Income ($000s) |
|---|---|---|---|---|---|
| 1 | Tennessee Gas Pipeline Co. | 11,917 | 2,990,155 | 1,192,621 | 331,768 |
| 2 | Texas Eastern Transmission LP | 9,592 | 2,610,451 | 1,165,248 | 318,519 |
| 3 | Dominion Transmission Inc. | 3,842 | 1,151,691 | 1,042,755 | 308,512 |
| 4 | Transcontinental Gas Pipe Line Co. LLC | 9,183 | 4,655,090 | 1,413,206 | 289,463 |
| 5 | Florida Gas Transmission Co. LLC | 5,324 | 902,592 | 795,990 | 234,412 |
| 6 | Columbia Gas Transmission LLC | 9,641 | 1,379,418 | 1,116,715 | 200,271 |
| 7 | Northern Natural Gas Co. | 14,781 | 1,025,465 | 749,039 | 150,275 |

8 Southern Natural Gas Co. 7,033 961,725 577,037 146,469

9 ETC Tiger Pipeline LLC 196 340,851 279,299 130,851

10 Kinder Morgan Lousiana Pipeline LLC 136 2,803 265,334 130,678

11 Natural Gas Pipeline Co. of America 9,122 1,417,903 651,548 116,693

12 Rockies Express Pipeline LLC 1,712 789,454 805,485 116,630

13 El Paso Natural Gas Co. 10,222 1,318,671 577,604 113,429

14 Colorado Interstate Gas Co. 4,225 839,291 402,882 108,983

15 Northwest Pipeline LLC 3,890 686,974 470,050 107,172

16 Dominion Cove Point LNG LP 136 92,710 296,555 97,654

17 Texas Gas Transmission LLC 5,766 1,154,029 406,562 97,237

18 Enable Gas Transmission LLC 5,902 913,254 494,067 93,115

19 Lake Charles LNG Co. LLC1 (new) - - 216,247 92,236

20 Equitrans LP 900 635,883 268,052 92,036

TOTAL FOR TOP 20 113,520 23,868,410 13,186,296 3,276,403

TOTAL FOR ALL COMPANIES 195,194 46,293,010 24,514,239 4,776,194

Source: Oil and Gas Journal. September 7, 2015. "Gas Pipeline Table" pp.126-128.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the major U.S. energy producers and reports summary information in the publication "The Performance Profiles of Major Energy Producers".11 This information is used in annual report to Congress, and is released to the public in aggregate form. While the companies that report information to the FRS each year changes,

11 The "Performance Profiles of Major Energy Producers 2009" released on February 25, 2011 is the most recent release of this report.



the EIA makes an effort to retain sufficient consistency to reliably evaluate trends. For 2009, 30 companies in the FRS12 accounted for 43 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 78 percent of U.S. refining capacity, and 0.3 percent of U.S. electricity net generation (U.S. EIA, 2011). Table 2-22 aggregates a series of financial trends selected from the FRS firms' financial statements presented in 2008 dollars. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well, followed by all three financial factors dropping off significantly in 2009. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, though the decrease in net income spans both 2008 and 2009 mainly as a factor of oil and natural gas prices declining significantly during the latter half of 2008.

12 Alenco, Alon USA, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chalmette, Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., Western Refining, WRB Refining LLC, and XTO Energy, Inc.



Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

| Year | Operating Revenues | Operating Expenses | Operating Income | Interest Expense | Other Income* | Income Taxes | Net Income |
|---|---|---|---|---|---|---|---|
| 1990 | 766.9 | 706.4 | 60.5 | 16.8 | 13.6 | 24.8 | 32.5 |
| 1991 | 673.4 | 635.7 | 37.7 | 14.4 | 13.4 | 15.4 | 21.3 |
| 1992 | 670.2 | 637.2 | 33.0 | 12.7 | -5.6 | 12.2 | 2.5 |
| 1993 | 621.4 | 586.6 | 34.8 | 11.0 | 10.3 | 12.7 | 21.5 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1994 | 606.5 | 565.6 | 40.9 | 10.8 | 6.8 | 14.4 | 22.5 |
| 1995 | 640.8 | 597.5 | 43.3 | 11.1 | 12.9 | 17.0 | 28.1 |
| 1996 | 706.8 | 643.3 | 63.6 | 9.1 | 13.4 | 26.1 | 41.8 |
| 1997 | 673.6 | 613.8 | 59.9 | 8.2 | 13.4 | 23.9 | 41.2 |
| 1998 | 614.2 | 594.1 | 20.1 | 9.2 | 11.0 | 6.0 | 15.9 |
| 1999 | 722.9 | 682.6 | 40.3 | 10.9 | 12.7 | 13.6 | 28.6 |
| 2000 | 1,114.3 | 1,011.8 | 102.5 | 12.9 | 18.4 | 42.9 | 65.1 |
| 2001 | 961.8 | 880.3 | 81.5 | 10.8 | 7.6 | 33.1 | 45.2 |
| 2002 | 823.0 | 776.9 | 46.2 | 12.7 | 7.9 | 17.2 | 24.3 |
| 2003 | 966.9 | 872.9 | 94.0 | 10.1 | 19.5 | 37.2 | 66.2 |
| 2004 | 1,188.5 | 1,051.1 | 137.4 | 12.4 | 20.1 | 54.2 | 90.9 |
| 2005 | 1,447.3 | 1,263.8 | 183.5 | 11.6 | 34.6 | 77.1 | 129.3 |
| 2006 | 1,459.0 | 1,255.0 | 204.0 | 12.4 | 41.2 | 94.8 | 138.0 |
| 2007 | 1,475.0 | 1,297.7 | 177.3 | 11.1 | 47.5 | 86.3 | 127.4 |
| 2008 | 1,818.1 | 1,654.0 | 164.1 | 11.4 | 32.6 | 98.5 | 86.9 |
| 2009 | 1,136.8 | 1,085.9 | 50.8 | 10.8 | 18.7 | 29.5 | 29.3 |

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

* Other Income includes other revenue and expenses (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

Table 2-23 shows the estimated return on investments in percentage terms for a variety of business lines in 1998, 2003, 2008, and 2009 for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production was the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent in 1998, 2003, and 2008, with a significant decrease in 2009. Returns to foreign oil and natural gas production rose above domestic production in 2008 and 2009. Electric power generation and sales emerged as a highly profitable line of business in 2008 for the FRS companies quickly followed by a significant decline in 2009.



Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, 2008, and 2009 (percent)

| Line of Business | 1998 | 2003 | 2008 | 2009 |
|---|---|---|---|---|
| Petroleum | 10.8 | 13.4 | 11.9 | 4.5 |
| U.S. Petroleum | 10 | 13.7 | 8.1 | 0.4 |
| Oil and Natural Gas Production | 12.5 | 16.5 | 10.7 | 3.5 |

Refining/Marketing 6.6 9.3 2.4 -6.6

Pipelines 6.7 11.5 2.4 4.7

Foreign Petroleum 11.9 13.0 17.8 10.3

Oil and Natural Gas Production 12.5 14.2 16.3 11

Refining/Marketing 10.6 8.0 26.2 5.8

Downstream Natural Gas* - 8.8 5.1 9.6

Electric Power - 5.2 181.4 -32

Other Energy 7.1 2.8 -2.1 5.1

Non-energy 10.9 2.4 -5.3 2.8

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Note: Return on investment measured as contribution to net income/net investment in place.

* The downstream natural gas and electric power lines of business were added to the EIA-28 survey form

beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state,

and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2009

for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes

deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008)13 and the effect of

the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local

authorizes were $3,060 million in 200813, about 13 percent of the total paid to U.S. authorities.

The difference between total current taxes and U.S. federal, state, and local taxes includes

taxes and royalties paid to foreign countries. As can be seen in Table 2-24 foreign taxes paid far

exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost

three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other

production-related taxes.

13 Data was withheld in 2009 to avoid disclosure.



Table 2-24 Income and Production Taxes, 1990-2009 (Million 2008 Dollars)

Year

US Federal, State,

and Local Taxes

Paid or Accrued Total Current

Total

Deferred

Total Income

Tax Expense

Other

Production

Taxes Paid

| | | | | | |
|---|---|---|---|---|---|
| 1990 | 9,568 | 25,056 | -230 | 24,826 | 4,341 |
| 1991 | 6,672 | 18,437 | -3,027 | 15,410 | 3,467 |
| 1992 | 4,994 | 16,345 | -4,116 | 12,229 | 3,097 |
| 1993 | 3,901 | 13,983 | -1,302 | 12,681 | 2,910 |
| 1994 | 3,348 | 13,556 | 887 | 14,443 | 2,513 |
| 1995 | 6,817 | 17,474 | -510 | 16,965 | 2,476 |
| 1996 | 8,376 | 22,493 | 3,626 | 26,119 | 2,922 |
| 1997 | 7,643 | 20,764 | 3,141 | 23,904 | 2,743 |
| 1998 | 1,199 | 7,375 | -1,401 | 5,974 | 1,552 |
| 1999 | 2,626 | 13,410 | 140 | 13,550 | 2,147 |
| 2000 | 14,308 | 36,187 | 6,674 | 42,861 | 3,254 |
| 2001 | 10,773 | 28,745 | 4,351 | 33,097 | 3,042 |
| 2002 | 814 | 17,108 | 46 | 17,154 | 2,617 |
| 2003 | 9,274 | 30,349 | 6,879 | 37,228 | 3,636 |
| 2004 | 19,661 | 50,185 | 4,024 | 54,209 | 3,990 |
| 2005 | 29,993 | 72,595 | 4,529 | 77,125 | 5,331 |
| 2006 | 29,469 | 85,607 | 9,226 | 94,834 | 5,932 |
| 2007 | 28,332 | 84,119 | 2,188 | 86,306 | 7,501 |
| 2008 | 23,199 | 95,590 | 2,866 | 98,456 | 12,507 |
| 2009* | -1,655 | 35,478 | -5,988 | 29,490 | -173 |

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

*In 2009, data on the U.S. Federal Investment Tax Credit and U.S. State and Local Income Taxes were withheld to

avoid disclosure.

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# 3 EMISSIONS AND ENGINEERING COSTS

## 3.1 Introduction

This chapter describes the emissions and engineering cost analysis for the final NSPS. The first section discusses the emissions points and control options. The following section describes each step in the emissions and engineering cost analysis and presents an overview of results. Detailed tables describing the impacts for each source and option can be found at the end of the chapter. We provide reference to the detailed Technical Support Document (TSD) prepared by the EPA for the reader interested in a greater level of detail.14

## 3.2 Sector Emissions Overview

This section provides estimates of overall emissions from the crude oil and natural gas industry to provide context for estimated reductions as a result of the rule. Crude oil and natural gas production sector VOC emissions are approximately 2.8 million tons, according to the 2011 EPA National Emissions Inventory (NEI). The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 (to be published April 15, 2016) estimates 2014 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 232 MMt $CO_2$ Eq. In 2014, total methane emissions from the oil and gas industry represented 32 percent of the total methane emissions from all sources and account for about 3 percent of all $CO_2$ Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2016).

For the analysis supporting this final action, including this RIA, we used the methane 100-year global warming potential (GWP) of 25 to be consistent with and comparable to key

Agency emission quantification programs such as the Inventory of Greenhouse Gas Emissions and Sinks (GHG Inventory) and the Greenhouse Gas Reporting Program (GHGRP).15 The use of

14 U.S. EPA. 2016. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards.

15 See, for example Table A-1 to subpart A of 40 C.F.R. part 98.



the 100-year GWP of 25 for methane value is currently required by the UNFCCC for reporting of national inventories, such as the GHG Inventory. Updated estimates for methane GWP have been developed by IPCC (2013).16 The most recent 100-year GWP estimates for methane, which are presented in the IPCC Fifth Assessment Report (AR5, 2013), range from 28-36. In discussing the science and impacts of methane emissions generally, we use the GWP range of 28-36. When presenting emissions estimates, we use the GWP of 25 for consistency and comparability with other emissions estimates in the U.S. and internationally.

3.3 Emissions Points and Pollution Controls assessed in the RIA

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. Additional technical details on the engineering and cost basis of the analysis is presented in the TSD.

Completions of Hydraulically Fractured and Re-fractured Oil Wells: Well completion activities include multiple steps after the well bore hole has reached the target depth. The highest emissions are from venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. The TSD separately considers developmental wells and exploratory wells. Developmental wells are wells drilled within known boundaries of a proven oil or gas field, while exploratory or "wildcat" wells are wells drilled in areas of new or unknown potential.

The EPA considered techniques that have been proven to reduce emissions from well completions: reduced emissions completions (RECs) and completion combustion, as well as reinjecting

the natural gas back into the well or another well, using the gas as an on-site fuel

source, or use for another beneficial purpose. The use of a REC not only reduces emissions but

delivers natural gas product that would typically be vented to the sales meter. Completion

combustion destroys the organic compounds. Technical barriers to the operation of a separator

16 IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth

Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M.

Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University

Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp.



such as well pressure and flowback composition can limit the feasibility of RECs in some

situations. Other barriers, such as proximity of pipelines, may prevent recovered gas from being

routed to a sales line, but do not necessarily prevent reinjection or on-site use.

Fugitive Emissions: There are several potential sources of fugitive emissions throughout

the oil and natural gas sector. Fugitive emissions occur when connection points are not fitted

properly or when seals and gaskets start to deteriorate. Changes in pressure and pressure or

mechanical stresses can also cause components or equipment to leak. Potential sources of

fugitive emissions include valves, connectors, pressure relief devices, open-ended lines, flanges,

closed vent systems, and thief hatches or other openings on a controlled storage unit. These

fugitive emissions do not include devices that vent as part of normal operations.

The TSD considers fugitive emissions from production wellsites and compressor stations.

The EPA considered two options for reducing methane and VOC emissions from leaking

components: a leak monitoring program based on individual component monitoring using EPA

Method 21 for leak detection combined with a leak correction, and a leak monitoring program

based on the use of OGI leak detection combined with leak correction. In addition, alternative

frequencies for fugitive emissions surveys were considered: annual, semiannual, and quarterly.

Pneumatic Controllers: Pneumatic controllers are automated instruments used for

maintaining a process condition such as liquid level, pressure, pressure differential, and

temperature. In many situations across all segments of the oil and natural gas industry, pneumatic

controllers make use of the available high-pressure natural gas to operate or control a valve. In

these "gas-driven" pneumatic controllers, natural gas may be released with every valve

movement and/or continuously from the valve control pilot. Not all pneumatic controllers are gas

driven. These "non-gas driven" pneumatic controllers use sources of power other than

pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas

locations with electrical service, non-gas-driven controllers are typically used. Continuous bleed

pneumatic controllers can be classified into two types based on their emissions rates: (1) highbleed

controllers and (2) low-bleed controllers. The EPA evaluated the impact of replacing highbleed

controllers with low-bleed controllers.

Pneumatic Pumps: Pneumatic pumps are devices that use gas pressure to drive a fluid



by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or a

set of rotating impellers. Gas powered pneumatic pumps are generally used at oil and natural gas

production sites where electricity is not readily available (GRI/EPA, 1996) and can be a

significant source of methane and VOC emissions. Pneumatic chemical and methanol injection

pumps are generally used to pump small volumes of chemicals or methanol into well bores,

surface equipment, and pipelines. Typically, these pumps include plunger pumps with a

diaphragm or large piston on the gas end and a smaller piston on the liquid end to enable a high

discharge pressure with a varied but much lower pneumatic supply gas pressure. They are

typically used semi-continuously with some seasonal variation. Pneumatic diaphragm pumps are

used widely in the onshore oil and gas sector to move larger volumes of liquids per unit of time

at lower discharge pressures than chemical and methanol injection pumps. The usage of these

pumps is episodic including transferring bulk liquids such as motor oil, pumping out sumps, and

circulation of heat trace medium at wellsites in cold climates during winter months.

For both of these types of pumps, emissions occur when the gas used in the pump stroke

is exhausted to enable liquid filling of the liquid chamber side of the diaphragm. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratio's between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump. As discussed in the white papers, several options for reducing methane and VOC emissions were identified: replace a natural gas-assisted pump with an instrument air pump, replace a natural gas-assisted pump with a solar-charged direct current pump (solar pumps), replace a natural gas-assisted pump with an electric pump, and route pneumatic pump emissions to a control device. The EPA evaluated the impact of routing pump emissions to a pre-existing on-site control device.

Centrifugal and Reciprocating Compressors: Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors.

Centrifugal compressors use either wet or dry seals.

Emissions from compressors occur when natural gas leaks around moving parts in the



compressor. In a reciprocating compressor, emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. Over time, during operation of the compressor, the rod packing system becomes worn and will need to be replaced to prevent excessive leaking from the compression cylinder. The control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includes replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

Emissions from centrifugal compressors depend on the type of seal used: either "wet", which use oil circulated at high pressure, or "dry", which use a thin gap of high pressure gas. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency. Limiting or reducing the emission from the rotating shaft of a centrifugal compressor using a mechanical dry seal system was evaluated. For centrifugal compressors equipped with wet seals, a flare was evaluated as an option for reducing

emissions from centrifugal compressors.

3.4 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate

the additional private expenditures industry may make to comply with the NSPS. A detailed

discussion of the methodology used to estimate cost impacts is presented in the TSD.

The following sections describe each step in the engineering cost analysis. First,

representative facilities are established for each source category, including baseline emissions

and control options. Second, the number of incrementally affected facilities for each type of

equipment or facility are projected. National emissions reductions and cost estimates are

calculated by multiplying representative factors, from the first step, by the estimated number of

affected facilities in each projection year, from the second step. In addition to emissions

reductions, some control options result in natural gas recovery, which can then be combusted for

useful processes or sold. The national cost estimates include estimated revenue from product

recovery where applicable.



3.4.1 Regulatory Options

For each emissions source, point, and control option, the TSD develops a representative

facility. The characteristics of this facility include typical equipment, operating characteristics,

and representative factors including baseline emissions and the costs, emissions reductions, and

product recovery resulting from each control option. In this RIA, we examine three broad

regulatory options. Table 3-1 shows the emissions sources, points, and controls for the three

NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3.

Option 2 was selected for promulgation.



Table 3-1 Emissions Sources and Controls Evaluated for the NSPS

Emissions Point Emissions Control

Option 1

Option 2

(final)

Option 3

Well Completions and Recompletions

Hydraulically Fractured

Development Oil Wells

REC / Combustion X X X

Hydraulically Fractured Wildcat

and Delineation Oil Wells

Combustion X X X

Fugitive Emissions

Well Sites

Planning,

Monitoring and

Maintenance

Annual Semiannual Quarterly

Gathering and Boosting Stations

Planning,

Monitoring and

Maintenance

Semiannual Quarterly Quarterly

Transmission Compressor Stations

Planning,

Monitoring and

Maintenance

Semiannual Quarterly Quarterly

Pneumatic Pumps

Well Sites Route to control X X X

Pneumatic Controllers

Natural Gas Transmission and

Storage

Emissions limit X X X

Reciprocating Compressors

Natural Gas Transmission and

Storage

Maintenance X X X

Centrifugal Compressors

Natural Gas Transmission and

Storage

Route to control X X X

The selected Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 requires fugitive emissions survey and repair programs be semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, and pneumatic controllers throughout the oil and natural gas source category.

The unselected Options 1 and 3 differ from the selected Option 2 with respect to the requirements for fugitive emissions. Option 1 requires fugitive emissions survey and repair



programs be performed annually at the affected newly drilled or refractured oil and natural gas well sites, and semiannually at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Fewer surveys being performed leads to lower costs and emissions reductions than under the selected Option 2. Finally, the more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. More frequent surveys result in higher costs and higher emissions reductions than Option 2.

3.4.2 Projection of Incrementally Affected Facilities

The second step in estimating national costs and emissions impacts of the final rule is projecting the number of incrementally affected facilities. Incrementally affected facilities are facilities that would be expected to change their emissions control activities as a result of the NSPS. Facilities in states with similar state-level requirements and facilities with only recordkeeping requirements are not included within incrementally affected facilities.

The years of analysis are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period. Therefore, the emissions reductions, benefits, and costs by 2020 and 2025 (i.e., including all emissions reductions, costs, and benefits in all years from 2016 to 2025) would be potentially significantly greater than the estimated emissions reductions, benefits, and costs provided within this rule. Affected facilities are facilities that are new or modified since the proposal in September 2015. In 2020, affected facilities are those that are newly established or modified in 2020, as well as those that have accumulated between 2016 and 2019. Over time, more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS accumulates. In 2025, affected facilities include facilities newly established or modified in 2025, and also facilities which were newly established or modified from 2016 through 2024 and are still operating in 2025. The analysis has assumed that all new equipment and facilities established from 2016 through 2024 are still in operation in 2025. This approach differs from the way affected facilities were estimated in the proposal RIA.

At proposal, 2020 was assumed to represent a single year of potential impacts, and 2025 included newly established or modified facilities from 2020 through 2024. This methodological



change results in a higher estimate of the number of affected facilities than at proposal and better represents the impacts of the rule.

The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels taken from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year changes over the past ten years in the GHG Inventory. New and modified hydraulically fractured oil well completions and wellsites are based on projections and growth rates consistent with the drilling activity in the Annual Energy Outlook. For the final RIA, the projections have been updated to reflect the projections in the 2015 Annual Energy Outlook. In addition, while the projections used in the proposal RIA were based on the long-term growth trajectory from 2012 to 2025, the current analysis is based on the full times series in the 2015 AEO reference scenario.

The 2015 Annual Energy Outlook was the most recent projection available at the time the analysis underlying this RIA was being prepared. The 2015 AEO includes the growth in U.S.

crude oil production over the last two years, along with the late-2014 drop in global crude oil prices, and reflects how these factors have altered the economics of the oil market. In comparison to the 2014 AEO reference case, the 2015 AEO reference case shows higher crude oil production (18 percent higher for 2025 in the 2015 AEO), slightly lower natural gas production (about 4 percent lower for 2025 in the 2015 AEO), lower Brent spot and West Texas Intermediate crude oil prices, and lower total wells drilled in the lower 48 states (about 20 percent lower for 2025 in the 2015 AEO).

While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to largely because of the limited information available on the turnover rate of emissions sources and controls. For this RIA, we have used the U.S. EIA's National Energy Modelling System (NEMS) to generate a limited set of future year projections to inform impact estimates for subset of affected sources. We also used the model to estimate key market impacts of the rules, based upon EPA's parameterization of regulatory costs and natural gas capture in the model. While NEMS produces highly regarded projections of production and well drilling, and is useful to estimate market impacts of the NSPS, it is not a compliance model and does not directly model



affected units. In addition, in a dynamic industry like oil and natural gas, technological progress in control technology is also likely to be dynamic. These factors make it reasonable to use 2025 as the latest year of analysis as extending the analysis beyond 2025 would introduce substantial and increasing uncertainties in projected impacts of the NSPS.

We also reviewed state regulations and permitting requirements which require mitigation measures for many emission sources in the oil and natural gas sector. State regulations in Colorado and Wyoming both require RECs for hydraulically fractured oil and gas wells, and North Dakota requires combustion of completion emissions. Sources in Colorado, Wyoming, Utah, and Ohio are subject to fugitive emissions requirements. Applicable facilities in these states are not included in the estimates of incrementally affected facilities presented in the RIA, as sources in those states are already subject to similar requirements to the federal standards.

This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements (e.g., to comply with the on-site separator requirement) are not reflected in this RIA. A more detailed discussion on the derivation of the baseline for this rule is presented for each emissions source in the TSD. In section 4.3.1 of the TSD, Table 4-3 provides a detailed breakout of affected oil well completions.

Table 3-2 Incrementally Affected Sources under Final NSPS, 2016 to 2025 on an Annual Basis

| Emissions Sources | Incrementally Affected Sources1 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
| Oil Well Completions and Recompletions | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 13,000 | 14,000 | 14,000 |
| Fugitive Emissions | 19,000 | 19,000 | 19,000 | 19,000 | 19,000 | 19,000 | 19,000 | 20,000 | 20,000 | 21,000 |
| Pneumatic Pumps | 790 | 790 | 790 | 790 | 790 | 790 | 790 | 790 | 790 | 790 |
| Compressors | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Pneumatic Controllers | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| Total | 32,000 | 32,000 | 33,000 | 33,000 | 33,000 | 33,000 | 33,000 | 34,000 | 35,000 | 35,000 |

1 Incrementally affected sources includes sources that have to change their control activity as a result of the rule. The table does not include estimate counts of a) affected facilities in states with similar state-level requirements to the NSPS, b) facilities with only recordkeeping requirements, or c) replacement or modification of existing sources except in the case of oil well completions and fugitive emissions at wellsites.

Table 3-2 presents the number of affected sources for each year of analysis after generally accounting for state regulations. In addition to the caveats regarding facilities affected by state regulations described above, facilities with only recordkeeping requirements are also not



included within incrementally affected facilities (e.g., wells with low GOR are not included in the estimate of facilities affected by the oil well completion requirements).

Table 3-3 Total Number of Affected Sources for the NSPS in 2020 and 2025

| Emissions Sources | Affected Sources1 | |
|---|---|---|
| | 2020 | 2025 |

Hydraulically Fractured and Re-fractured Oil Well Completions 13,000[3] 14,000[3]

Fugitive Emissions 94,000 190,000

Pneumatic Pumps 3,900 7,900

Compressors 170 330

Pneumatic Controllers 480 960

Total[2] 110,000 220,000

1 In addition to newly affected sources in 2020, total affected sources in 2020 include sources that become affected

in the 2016-2019 period and are assumed to be in continued operation in 2020. Similarly, affected sources in 2025

reflect sources newly constructed or modified from 2016 to 2025, assumed to still be in operation in 2025. The table

does not include estimate counts of: a) affected facilities in states already regulating those sources, b) facilities with

only recordkeeping requirements, or c) replacement or modification of existing sources except for oil well

completions and fugitive emissions at wellsites. Estimates are rounded to two significant digits.

2 Totals may not sum due to independent rounding.

3 Affected oil well completions include a mix of RECs and flaring based on subcategory and technical infeasibility

criteria. Exploratory and delineation wells are required to combust emissions. Of development oil well completions,

50% are estimated to be feasible to perform a REC; the remainder would combust emissions (either because they are

unable to implement a REC due to low pressure or other technical infeasibility reasons). See section 4.3.1 of the

TSD for a detailed breakout of affected oil well completions

Table 3-3 presents estimates of the total number of affected sources for this final rule.

Note that hydraulically fractured and re-fractured oil well completions do not grow significantly

from 2020 to 2025, while other sources do. This is a result of completions being a one-time

activity in a given year, while other sources are affected and remain affected as they continue to

operate, thus these sources accumulate over time. The estimates for hydraulically fractured and

re-fractured oil well completions and fugitive emissions at wellsites (a large fraction of the

incrementally affected sources under the fugitive emissions provisions) include both new and

modified sources.

The estimates for other sources are based upon projections of new sources alone, and do

not include replacement or modification of existing sources. While some of these sources are

unlikely to be modified, particularly pneumatic pumps and controllers, the impact estimates may

be under-estimated due to the focus on new sources. In the proposal, the EPA solicited

comments on these projection methods as well as solicits information that would improve our



estimate of the turnover rates or rates of modification of relevant sources, as well as the number

of wells on wellsites. While the EPA received comments on the projection methods used in the

proposal RIA, we did not receive comments with sufficient information to further incorporate

modification and turnover in the projection methodologies. The EPA has modified its

methodology for using historical inventory information to estimate new sources reflecting

comments received, resulting in lower estimates of the number of new compressor stations,

pumps, compressors, and pneumatic controllers constructed each year. Newly constructed

affected facilities are estimated based on averaging the year-to-year changes in the past 10 years

of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps,

compressors, and pneumatic controllers. At proposal, this was done by averaging the increasing

years only. The approach was modified to average the number of newly constructed units in all

years. In years when the total count of equipment decreased, there were assumed to be no newly

constructed units.

### 3.4.3 Emissions Reductions

Table 3-4 summarizes the national emissions reductions for the evaluated NSPS

emissions sources and points for 2020 and 2025. These reductions are estimated by multiplying

the unit-level emissions reductions associated with each applicable control and facility type by

the number of incrementally affected sources. The detailed description of emissions controls is

provided in the TSD. Please note that all results have been rounded to two significant digits.



Table 3-4 Emissions Reductions for Final NSPS Option 2, 2020 and 2025

Source/Emissions

Point

Emissions Reductions, 2020

Methane

(short tons)

| | | VOC (short tons) | HAP (short tons) | Methane (metric tons CO2 Eq.) |
|---|---|---|---|---|
| Oil Well Completions and Recompletions | 120,000 | 97,000 | 12 | 2,600,000 |
| Fugitive Emissions | 170,000 | 46,000 | 1,700 | 3,800,000 |
| Pneumatic Pumps | 13,000 | 3,600 | 140 | 290,000 |
| Compressors | 4,000 | 110 | 3 | 92,000 |
| Pneumatic Controllers | 1,300 | 37 | 1 | 30,000 |
| Total | 300,000 | 150,000 | 1,900 | 6,900,000 |

| Source/Emissions Point | Emissions Reductions, 2025 | | | |
|---|---|---|---|---|
| | Methane (short tons) | VOC (short tons) | HAP (short tons) | Methane (metric tons CO2 Eq.) |
| Oil Well Completions and Recompletions | 120,000 | 100,000 | 12 | 2,800,000 |
| Fugitive Emissions | 350,000 | 94,000 | 3,600 | 7,900,000 |
| Pneumatic Pumps | 26,000 | 7,200 | 270 | 590,000 |
| Compressors | 8,100 | 220 | 7 | 180,000 |
| Pneumatic Controllers | 2,700 | 74 | 2 | 61,000 |
| Total | 510,000 | 210,000 | 3,900 | 11,000,000 |

### 3.4.4 Product Recovery

The annualized cost estimates presented below include revenue from additional natural gas recovery. Several emission controls for the NSPS capture methane and VOC emissions that would otherwise be vented to the atmosphere. A large proportion of the averted methane emissions can be directed into natural gas production streams and sold. For the environmental controls that avert the emission of saleable natural gas, we base the estimated revenues from



averted natural gas emissions on an estimate of the amount of natural gas that would not be emitted during one year.

The controls that result in natural gas recovery are: RECs at hydraulically fractured oil wells, fugitive emissions monitoring and repair, rod packing replacement in reciprocating compressors, and the use of low-bleed pneumatic devices. The requirements for completions at exploration and delineation wells, pneumatic pumps, and centrifugal compressors do not result in natural gas recovery. In some of these cases, alternative control strategies do result in natural gas recovery, but these alternative controls were not assumed as part of this analysis. For example, alternatives to routing pneumatic pump emissions to a control device include substituting a solar or electric pump where a gas-driven pump would have otherwise been used.

Table 3-5 summarizes natural gas recovery and revenue included in annualized cost calculations. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead.

The EIA's 2015 Annual Energy Outlook reference case projects Henry Hub natural gas prices to be $4.88/MMBtu in 2020 and $5.46/MMBtu in 2025 in 2013 dollars.17 After adjusting to $/Mcf (using the conversion of 1 MMBtu = 1.028 Mcf) in 2012 dollars (using the GDP-Implicit Price Deflator), these prices are $4.94/Mcf in 2020 and $5.52 in 2025. When including the additional natural gas recovery in the main cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The $4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low and also account for markup on the natural gas between the wellhead and the Henry Hub for processing and transportation.18

Operators in the gathering and boosting, and transmission and storage parts of the industry do not typically own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and presented in Volume 1 of

17 Available at: http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

18 An EIA study indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price.

See http://www.eia.gov/oiaf/analysispaper/henryhub/.



the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Table 3-5 Estimated Natural Gas Recovery (Mcf) for selected Option 2 in 2020 and 2025

| Source/Emissions Point | 2020 | | 2025 | |
|---|---|---|---|---|
| | Gas recovery (Mcf) | Value of recovery | Gas recovery (Mcf) | Value of recovery |
| Oil Well Completions and Recompletions | 5,700,000 | $23,000,000 | 6,100,000 | $24,000,000 |
| Fugitive Emissions | 9,800,000 | $39,000,000 | 20,000,000 | $80,000,000 |
| Pneumatic Pumps | 0 | $0 | 0 | $0 |

Compressors 180,000 $720,000 360,000 $1,400,000

Pneumatic Controllers 69,000 $280,000 140,000 $550,000

Total 16,000,000 $63,000,000 27,000,000 $110,000,000

As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. In addition, there is geographic variability in wellhead prices, which can also influence estimated engineering costs. For Option 2, a $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about 5 percent. Section 3.5.2 further examines the sensitivity of national compliance costs to natural gas prices.

3.4.5 Engineering Compliance Costs



Table 3-6 summarizes the capital and annualized costs and revenue from product recovery for the evaluated emissions sources and points. The capital costs represent total capital cost expenditures associated with affected units in 2020 and 2025, including capital cost expenditures made prior to the analysis year. The detailed description of cost estimates is provided in TSD. To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. This approach is mathematically equivalent to establishing an overall, representative project time horizon and annualizing costs after consideration of control options that would need to be replaced periodically within the given time horizon.

Table 3-6 Engineering Compliance Cost Estimates for Final NSPS Option 2 in 2020 and 2025 (millions 2012$)

Source/Emissions Point

Compliance Costs, 2020

Capital

Costs1

Annualized

Costs (without

savings)

Revenue

from

Product

Recovery

Nationwide

Annualized Costs

with Addl. Revenue

(2012$)

Oil Well Completions and Recompletions $150 $150 $23 $130

Fugitive Emissions $77 $230 $39 $190

Pneumatic Pumps $21 $3 $0 $3.1

Compressors $1.4 $0.9 $0.7 $0.2

Pneumatic Controllers $0.1 $0.0 $0.3 -$0.27

Reporting and Recordkeeping $0 $6.3 $0 $6.3

Total $250 $390 $63 $320

Source/Emissions Point

Compliance Costs, 2025

Capital

Costs1

Annualized

Costs (without

savings)

Revenue

from

Product

Recovery

Nationwide

Annualized Costs

with Addl. Revenue

(2012$)

Oil Well Completions and Recompletions $160 $160 $24 $130

Fugitive Emissions $160 $460 $80 $380

Pneumatic Pumps $43 $6 $0 $6

Compressors $2.9 $1.8 $1.4 $0.3

Pneumatic Controllers $0.2 $0.0 $0.6 -$0.5

Reporting and Recordkeeping $0.0 $6.3 $0 $6.3

Total $360 $640 $110 $530

1 Capital costs represent total capital costs associated with control of affected sources in 2020 and 2025, including

expenditures made in previous years. Sums may not total due to independent rounding.

Engineering capital costs were annualized using a 7 percent interest rate. Section 3.4



provides a comparison to using a 3 percent interest rate. Different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used to annualize capital costs of emissions controls:

• Reduced emissions completions and combustion devices: 1 year

• Fugitive emissions monitoring program design: 8 years

• Reciprocating compressors rod packing: 3.8 - 4.4 years

• Centrifugal compressors and pneumatic pumps: 10 years

• Pneumatic controllers: 15 years

Note the large majority of capital costs are required for the completions fugitive emissions requirements. Alternative assumptions of the lifetimes of these expenditures are most likely influence estimates of total compliance costs, where alternative assumptions for compressors, pumps, and controllers would likely to have relatively small effects.

Reporting and recordkeeping costs were drawn from the information collection requirements (ICR) in this final rule that have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (see Preamble for more detail). The 2020 and 2025 reporting and recordkeeping costs in this RIA are assumed to be equal to the third year cost reporting in the ICR cost estimates ($6.3 million). These recordkeeping and recordkeeping costs are estimated for the selected Option 2 for all new and modified facilities regardless of whether they implement additional controls as a result of the NSPS. While these costs may differ across regulatory options as a result of the varying frequency of the fugitives program across the options, we do not have the information to estimate the ICR burden for the unselected Option 1 and 3. As a result, we assume all options have the same recordkeeping and reporting cost burden. Note also that reporting and recordkeeping costs are included for all affected entities, regardless of whether they are in states with regulatory requirements similar to the final NSPS.

3.4.6 Comparison of Regulatory Alternatives



Table 3-7 presents a comparison of the regulatory alternatives through each step of the emissions analysis in 2020 and 2025. The requirements between the options vary with respect to the fugitive emissions requirements. The less stringent Option 1 requires annual monitoring for well sites under the fugitive emissions program and semi-annual for compressor stations. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program. Annual, semi-annual, and quarterly fugitive emissions surveys are assumed to result in reductions in emissions of 40 percent, 60 percent and 80 percent, respectively.[19] For more information on these assumptions, please see Section 4.3.2.2 of the TSD. Natural gas recovery also varies as a result of survey frequency. Variation in natural gas recovery, capital and annualized costs reflect these differences in the number of affected facilities and frequency of fugitive emissions surveys. In addition, the ratio between national compliance costs and national emissions reductions is presented using both the single pollutant and multipollutant approach.

Table 3-7 Comparison of Regulatory Alternatives

| Regulatory Alternative | Option 1 | Option 2 (final) | Option 3 |
|---|---|---|---|
| Impacts in 2020 | | | |
| Affected Sources | 110,000 | 110,000 | 110,000 |
| Emissions Reductions | | | |
| Methane Emissions Reduction (short tons/year) | 250,000 | 300,000 | 350,000 |
| VOC Emissions Reduction (short tons/year) | 130,000 | 150,000 | 160,000 |
| Natural Gas Recovery (Mcf) | 13,000,000 | 16,000,000 | 19,000,000 |
| Compliance Costs | | | |
| Capital Costs (2012$) | $240,000,000 | $250,000,000 | $260,000,000 |
| Annualized Costs Without Addl. Revenue (2012$) | $290,000,000 | $390,000,000 | $570,000,000 |
| Annualized Costs With Addl. Revenue (2012$) | $240,000,000 | $320,000,000 | $490,000,000 |
| Impacts in 2025 | | | |
| Affected Sources | 220,000 | 220,000 | 220,000 |
| Emissions Reductions | | | |
| Methane Emissions Reduction (short tons/year) | 390,000 | 510,000 | 610,000 |
| VOC Emissions Reduction (short tons/year) | 170,000 | 210,000 | 230,000 |

19 The EPA performed a sensitivity analysis based on the midpoints of the Method 21 emission reduction efficiency percentages, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. Even based on this conservative analysis, the EPA finds that the chosen monitoring

frequencies are the BSER for these sources. The EPA additionally concluded that the 40, 60, and 80 percent emission reduction efficiency percentages are reasonable and accurate. See section 4.3.2.2 of the final TSD for further information.

3-19

| | | | |
|---|---|---|---|
| Natural Gas Recovery (Mcf) | 20,000,000 | 27,000,000 | 33,000,000 |
| Compliance Costs | | | |
| Capital Costs (2012$) | $350,000,000 | $360,000,000 | $380,000,000 |
| Annualized Costs Without Addl. Revenue (2012$) | $440,000,000 | $640,000,000 | $1,000,000,000 |
| Annualized Costs With Addl. Revenue (2012$) | $360,000,000 | $530,000,000 | $880,000,000 |

3.5 Engineering Cost Sensitivity Analysis

This section illustrates the sensitivity of engineering cost and emissions analysis results of Option 2 to choice of discount rate and natural gas prices.

3.5.1 Compliance Costs Estimated Using 3 and 7 Percent Discount Rates

Table 3-8 shows that the choice of discount rate has minor effects on the nationwide annualized costs of the final rule.

Table 3-8 Annualized Costs using 3 and 7 Percent Discount Rates for Final NSPS Option 2 in 2020 and 2025 (millions 2012$)

| | Nationwide Annualized Costs, 2020 | | Nationwide Annualized Costs, 2025 | |
|---|---|---|---|---|
| | 7 percent | 3 percent | 7 percent | 3 percent |
| Oil Well Completions and Recompletions | $130 | $130 | $130 | $130 |
| Fugitive Emissions | $190 | $190 | $380 | $380 |
| Pneumatic Pumps | $3.1 | $2.5 | $6.1 | $5 |
| Compressors | $0.16 | $0.12 | $0.31 | $0.24 |
| Pneumatic Controllers | -$0.27 | -$0.27 | -$0.53 | -$0.54 |
| Reporting and Recordkeeping | $6.3 | $6.3 | $6.3 | $6.3 |
| Total | $320 | $320 | $530 | $520 |

The choice of discount rate has a small effect on nationwide annualized costs. Discount rate generally affects estimates of annualized costs for controls with high capital costs relative to annual costs. The compliance costs related to oil well completions and fugitive emissions surveys occur in each year, so the interest rate has little impact on annualized costs for these sources. The annualized costs for pneumatic pumps, compressors, and pneumatic controllers are



sensitive to interest rate, but these constitute a relatively small part of the total compliance cost estimates for the rule.

### 3.5.2 Sensitivity of Compliance Costs to Natural Gas Prices

The annualized compliance cost estimates presented in this RIA include revenue from additional natural gas recovery, and therefore national compliance costs depend the price of natural gas. This section examines the sensitivity of national compliance costs to varying natural gas prices. When including the additional natural gas recovery in the main cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. As discussed earlier, the $4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low and also account for markup on the natural gas between the wellhead and the Henry Hub for processing and transportation.

EPA recognizes that current natural gas prices are below $4/Mcf. In 2015, the Henry Hub Natural Gas Spot Price ranged between about $2 and $3 dollars per MMBtu (about $1.94/Mcf and $2.91/Mcf, respectively). 20 The models used to forecast natural gas prices in the Annual Energy Outlook are deterministic. A deterministic model does not incorporate potential stochastic influences and and will therefore producs the same result for each model run using all else equal. While the Annual Energy Outlook is a commonly referenced publication that provides mid-term forecasts, the U.S. EIA also produces the Short-Term Energy Outlook (STEO), which provides confidence intervals for some energy prices over a shorter time frame based on the prices paid for financial derivatives (e.g., options) based on natural gas. To better understand the uncertainty associated with the 2020 and 2025 natural gas price assumed in this analysis, EPA reviewed the March 2016 STEO, which includes monthly forecasted natural gas prices through 2017.21 While the STEO analysis only extends to the end of 2017, the published

20 Assuming the average heat context of natual gas is 1,028 Btu per cubic foot, 1 Mcf = 1.028 MMBtu. Based on this assumption, to convert natural gas prices denominated in MMbtu to Mcf, the $/MMbtu is multiplied by 1/1.028 or 0.973.

21 U.S. Energy Information Administration (U.S. EIA). 2016. Short-Term Energy Outlook, March 8, 2016. <http://www.eia.gov/forecasts/steo/report/natgas.cfm> March 8, 2016.



confidence intervals for future natural gas prices can provide some basis for understanding the potential uncertainty around slightly longer-term forecasts.

In the STEO, forecasted prices are traded futures contracts. Based on this information the STEO also presents a 95% confidence interval for the price of natural gas through 2017. However, that the probability analysis uses the Henry Hub spot price, rather than the wellhead price paid to producer. The EIA analysis projects an expected December 2017 Henry Hub price of \$3.31 per MMBtu (\$3.22/Mcf) with a 95 percent confidence interval of \$1.45 to \$5.25 per MMBtu (\$1.41/Mcf to \$5.10/Mcf). While this confidence interval is not for wellhead natural gas prices, it is relevant for understating the challenges associated with precisely predicting future natural gas prices.

To analyze the sensitivity of the engineering costs of the rule to assumed natural gas prices, Table 3-12 presents nationwide annualized costs for each source category assuming natural gas prices of \$2, \$3, \$4, and \$5 per Mcf.

Table 3-9 Annualized Costs Using Natural Gas Prices from \$2 to \$5 per Mcf

| Source/Emissions Point | Nationwide Annualized Costs (million 2012\$), 2020 | | | | Nationwide Annualized Costs (million 2012\$), 2025 | | | |
|---|---|---|---|---|---|---|---|---|
| | \$2/Mcf | \$3/Mcf | \$4/Mcf | \$5/Mcf | \$2/Mcf | \$3/Mcf | \$4/Mcf | \$5/Mcf |
| Oil Well Completions and Recompletions | \$140 | \$130 | \$130 | \$120 | \$150 | \$140 | \$130 | \$130 |
| Fugitive Emissions | \$210 | \$200 | \$190 | \$180 | \$420 | \$400 | \$380 | \$360 |
| Pneumatic Pumps | \$3.1 | \$3.1 | \$3.1 | \$3.1 | \$6.1 | \$6.1 | \$6.1 | \$6.1 |
| Compressors | \$0.52 | \$0.34 | \$0.16 | -\$0.023 | \$1 | \$0.68 | \$0.31 | -\$0.046 |
| Pneumatic Controllers | -\$0.13 | -\$0.20 | -\$0.27 | -\$0.33 | -\$0.25 | -\$0.39 | -\$0.53 | -\$0.67 |
| Reporting and Recordkeeping | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 | \$6.3 |
| Total | \$350 | \$340 | \$320 | \$310 | \$580 | \$560 | \$530 | \$500 |

Note that all figures are rounded to two significant digits. Annualized costs are estimated using a 7 percent discount

rate. Totals may not sum due to independent rounding.

For Option 2, a $1/Mcf change in the wellhead price causes a change in estimated

engineering compliance costs of about $16 million in 2020 and $27 million in 2025, in 2012

dollars. In percentage terms, a $1/Mcf reduction in the wellhead price causes about a 5 percent

increase in national compliance costs in either 2020 or 2025. These amounts include revenue

from product recovery in all segments. As decribed above, this approach differs with respect to



the gathering and boosting and transmission segments between the unit-level cost and emissions

reduction analysis supporting BSER decisions (which is focused on control costs borne by

regulated sources) and this RIA (which is focused on societal costs). Operators in the gathering

and boosting and transmission and storage segments may not own the natural gas they transport,

and so may not be able to offset compliance costs with revenue from product recovery in the

short term. Changes in costs are affected for the oil well completions, fugitive emissions sources,

reciprocating compressors, and pneumatic controllers because control of these sources results in

product recovery. Costs for pumps and centrifugal compressors are not affected because routing

emissions to a control does not result in product recovery. Valued at $4/Mcf, estimated national

gas recovery as a result of the NSPS in the gathering and boosting segment would be about $3

million in 2020 and $6 million in 2025 and in the transmission and storage segment would be

about $2 million in 2020 and $4 million in 2025.

3.6 Detailed Impacts Tables

The following tables show the full details of the costs and emissions reductions by

emissions sources for each regulatory option in 2020 and 2025.



Table 3-10 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2020

Source/Emissions Point

Projected No. of

Affected Units

For Which

Federal

Regulations

Require Further

Action

Nationwide Emissions Reductions National Costs

Methane

(short

tons/year)

VOC (short

tons/year)

HAP (short

tons/year)

Methane

(metric tons

CO2e) Capital Costs

Annualized

Costs With

Addl.

Revenues

Well Completions and Recompletions

Hydraulically Fractured Development

Oil Wells 12,000 110,000 89,000 11 2,400,000 $140,000,000 $120,000,000

Hydraulically Fractured Wildcat and

Dilineation Oil Wells 990 9,100 7,600 1 210,000 $3,700,000 $3,700,000

Fugitive Emissions

Well Pads 94,000 100,000 28,000 1,100 2,300,000 $71,000,000 $100,000,000

Gathering and Boosting Stations 480 10,000 2,800 110 230,000 $1,100,000 $4,200,000

Tranmission Compressor Stations 45 2,600 73 2 59,000 $740,000 $360,000

Pneumatic Pumps

Well Pads 3,900 13,000 3,600 140 290,000 $21,000,000 $3,100,000

Pneumatic Controllers -

Natural Gas Transmission and

Storage Stations 160 3,500 96 3 79,000 $1,100,000 -$410,000

Reciprocating Compressors

Natural Gas Transmission and

Storage Stations 5 560 15 0 13,000 $360,000 $570,000

Centrifigal Compressors

Natural Gas Transmission and

Storage Stations 480 1,300 37 1 30,000 $110,000 -$270,000

Reporting and Recordkeeping All 0 0 0 0 $0 $6,300,000

TOTAL 110,000 250,000 130,000 1,300 5,600,000 $240,000,000 $240,000,000



Table 3-11 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2025

Source/Emissions Point

Projected No. of

Affected Units

For Which

Federal

Regulations

Require Further

Action

Nationwide Emissions Reductions National Costs

Methane

(short

tons/year)

VOC (short

tons/year)

HAP (short

tons/year)

Methane

(metric tons

CO2e) Capital Costs

Annualized

Costs With

Addl.

Revenues

Well Completions and Recompletions

Hydraulically Fractured Development

Oil Wells 13,000 110,000 95,000 11 2,600,000 $150,000,000 $130,000,000

Hydraulically Fractured Wildcat and

Dilineation Oil Wells 1,100 10,000 8,400 1 230,000 $4,000,000 $4,000,000

Fugitive Emissions

Well Pads 190,000 210,000 58,000 2,200 4,700,000 $150,000,000 $200,000,000

Gathering and Boosting Stations 960 20,000 5,600 210 460,000 $2,300,000 $8,300,000

Tranmission Compressor Stations 90 5,200 150 4 120,000 $1,500,000 $710,000

Pneumatic Pumps

Well Pads 7,900 26,000 7,200 270 590,000 $43,000,000 $6,100,000

Pneumatic Controllers -

Natural Gas Transmission and

Storage Stations 320 7,000 190 6 160,000 $2,200,000 -$830,000

Reciprocating Compressors

Natural Gas Transmission and

Storage Stations 10 1,100 31 1 25,000 $720,000 $1,100,000

Centrifigal Compressors

Natural Gas Transmission and

Storage Stations 960 2,700 74 2 61,000 $220,000 -$530,000

Reporting and Recordkeeping All 0 0 0 0 $0 $6,300,000

TOTAL 220,000 390,000 170,000 2,700 8,900,000 $350,000,000 $360,000,000



Table 3-12 Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2020

Source/Emissions Point

Projected No. of

Affected Units

For Which

Federal

Regulations

Require Further

Action

Nationwide Emissions Reductions National Costs

Methane

(short

tons/year)

VOC (short

tons/year)

HAP (short

tons/year)

Methane

(metric tons

CO2e) Capital Costs

Annualized

Costs With

Addl.

Revenues

Well Completions and Recompletions

Hydraulically Fractured Development

Oil Wells 12,000 110,000 89,000 11 2,400,000 $140,000,000 $120,000,000

Hydraulically Fractured Wildcat and

Dilineation Oil Wells 990 9,100 7,600 1 210,000 $3,700,000 $3,700,000

Fugitive Emissions

Well Pads 94,000 150,000 42,000 1,600 3,500,000 $75,000,000 $180,000,000

Gathering and Boosting Stations 480 13,000 3,800 140 310,000 $1,100,000 $8,900,000

Tranmission Compressor Stations 45 3,500 97 3 79,000 $740,000 $880,000

Pneumatic Pumps

Well Pads 3,900 13,000 3,600 140 290,000 $21,000,000 $3,100,000

Pneumatic Controllers -

Natural Gas Transmission and

Storage Stations 160 3,500 96 3 79,000 $1,100,000 -$410,000

Reciprocating Compressors

Natural Gas Transmission and

Storage Stations 5 560 15 0 13,000 $360,000 $570,000

Centrifigal Compressors

Natural Gas Transmission and

Storage Stations 480 1,300 37 1 30,000 $110,000 -$270,000

Reporting and Recordkeeping 0 0 0 0 0 $0 $6,300,000

TOTAL 110,000 300,000 150,000 1,900 6,900,000 $250,000,000 $320,000,000



Table 3-13 Incrementally Affected Units, Emissions Reductions and Costs, Selected Option 2, 2025

Source/Emissions Point

Projected No. of

Affected Units

For Which

Federal

Regulations

Require Further

Action

Nationwide Emissions Reductions National Costs

Methane

(short

tons/year)

VOC (short

tons/year)

HAP (short

tons/year)

Methane

(metric tons

CO2e) Capital Costs

Annualized

Costs With

Addl.

Revenues

Well Completions and Recompletions

Hydraulically Fractured Development

Oil Wells 13,000 110,000 95,000 11 2,600,000 $150,000,000 $130,000,000

Hydraulically Fractured Wildcat and

Dilineation Oil Wells 1,100 10,000 8,400 1 230,000 $4,000,000 $4,000,000

Fugitive Emissions

Well Pads 190,000 310,000 87,000 3,300 7,100,000 $150,000,000 $360,000,000

Gathering and Boosting Stations 960 27,000 7,500 280 610,000 $2,300,000 $18,000,000

Tranmission Compressor Stations 90 7,000 190 6 160,000 $1,500,000 $1,800,000

Pneumatic Pumps

Well Pads 7,900 26,000 7,200 270 590,000 $43,000,000 $6,100,000

Pneumatic Controllers -

Natural Gas Transmission and

Storage Stations 320 7,000 190 6 160,000 $2,200,000 -$830,000

Reciprocating Compressors

Natural Gas Transmission and

Storage Stations 10 1,100 31 1 25,000 $720,000 $1,100,000

Centrifigal Compressors

Natural Gas Transmission and

Storage Stations 960 2,700 74 2 61,000 $220,000 -$530,000

Reporting and Recordkeeping 0 0 0 0 0 $0 $6,300,000

TOTAL 220,000 510,000 210,000 3,900 11,000,000 $360,000,000 $530,000,000



Table 3-14 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2020

Source/Emissions Point

Projected No. of

Affected Units

For Which

Federal

Regulations

Require Further

Action

Nationwide Emissions Reductions National Costs

Methane

(short

tons/year)

VOC (short

tons/year)

HAP (short

tons/year)

Methane

(metric tons

CO2e) Capital Costs

Annualized

Costs With

Addl.

Revenues

Well Completions and Recompletions

Hydraulically Fractured Development

Oil Wells 12,000 110,000 89,000 11 2,400,000 $140,000,000 $120,000,000

Hydraulically Fractured Wildcat and

Dilineation Oil Wells 990 9,100 7,600 1 210,000 $3,700,000 $3,700,000

Fugitive Emissions

Well Pads 94,000 200,000 57,000 2,100 4,600,000 $83,000,000 $350,000,000

Gathering and Boosting Stations 480 13,000 3,800 140 310,000 $1,100,000 $8,900,000

Tranmission Compressor Stations 45 3,500 97 3 79,000 $740,000 $880,000

Pneumatic Pumps

Well Pads 3,900 13,000 3,600 140 290,000 $21,000,000 $3,100,000

Pneumatic Controllers -

Natural Gas Transmission and

Storage Stations 160 3,500 96 3 79,000 $1,100,000 -$410,000

Reciprocating Compressors

Natural Gas Transmission and

Storage Stations 5 560 15 0 13,000 $360,000 $570,000

Centrifigal Compressors

Natural Gas Transmission and

Storage Stations 480 1,300 37 1 30,000 $110,000 -$270,000

Reporting and Recordkeeping 0 0 0 0 0 $0 $6,300,000

TOTAL 110,000 350,000 160,000 2,400 8,000,000 $260,000,000 $490,000,000



Table 3-15 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2025

Source/Emissions Point

Projected No. of

Affected Units

For Which

Federal

Regulations

Require Further

Action

Nationwide Emissions Reductions National Costs

Methane

(short

tons/year)

VOC (short

tons/year)

HAP (short

tons/year)

Methane

(metric tons

CO2e) Capital Costs

Annualized

Costs With

Addl.

Revenues

Well Completions and Recompletions

Hydraulically Fractured Development

Oil Wells 13,000 110,000 95,000 11 2,600,000 $150,000,000 $130,000,000

Hydraulically Fractured Wildcat and

Dilineation Oil Wells 1,100 10,000 8,400 1 230,000 $4,000,000 $4,000,000

Fugitive Emissions

Well Pads 190,000 420,000 120,000 4,400 9,400,000 $170,000,000 $710,000,000

Gathering and Boosting Stations 960 27,000 7,500 280 610,000 $2,300,000 $18,000,000

Tranmission Compressor Stations 90 7,000 190 6 160,000 $1,500,000 $1,800,000

Pneumatic Pumps

Well Pads 7,900 26,000 7,200 270 590,000 $43,000,000 $6,100,000

Pneumatic Controllers -

Natural Gas Transmission and

Storage Stations 320 7,000 190 6 160,000 $2,200,000 -$830,000

Reciprocating Compressors

Natural Gas Transmission and

Storage Stations 10 1,100 31 1 25,000 $720,000 $1,100,000

Centrifigal Compressors

Natural Gas Transmission and

Storage Stations 960 2,700 74 2 61,000 $220,000 -$530,000

Reporting and Recordkeeping 0 0 0 0 0 $0 $6,300,000

TOTAL 220,000 610,000 230,000 5,000 14,000,000 $380,000,000 $880,000,000



# 4 BENEFITS OF EMISSIONS REDUCTIONS

## 4.1 Introduction

The final NSPS is designed to prevent new emissions from the oil and gas sector. For the NSPS, we predict that there will be climate and ozone benefits from methane reductions, ozone and $PM_{2.5}$ health benefits from VOC reductions, and HAP "co-benefits". These co-benefits would occur because the control techniques to meet the standards simultaneously reduce methane, VOC, and HAP emissions. The NSPS is anticipated to prevent 300,000 tons of methane, 150,000 tons of VOC, and 1,900 tons of HAP from new sources in 2020. In 2025, the NSPS is estimated to prevent 510,000 tons of methane, 210,000 tons of VOC, and 3,900 tons of HAP. The $CO_2$-equivalent ($CO_2$ Eq.) methane emission reductions are estimated to be 6.9 million metric tons in 2020 and 11 million metric tons in 2025. As described in the subsequent sections, these pollutants are associated with substantial climate, health, and welfare effects. The only benefits monetized in this RIA are methane-related climate benefits. The methane-related climate effects are estimated to be $360 million and $690 million using a 3 percent discount rate in 2020 and 2025, respectively.22 The specific control techniques for the NSPS are anticipated to have minor emissions disbenefits (e.g., increases in emissions of carbon dioxide ($CO_2$), nitrogen oxides ($NO_X$), PM, carbon monoxide (CO), and total hydrocarbons (THC)) and emission changes associated with the energy markets impacts.

While we expect that the avoided VOC emissions will also result in improvements in air quality and reduce health and welfare effects associated with exposure to ozone, fine particulate matter ($PM_{2.5}$), and HAP, we have determined that quantification of the VOC-related health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that these benefits do not exist; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.

With the data available, we are not able to provide credible health benefits estimates for this rule,

due to the differences in the locations of oil and natural gas emission points relative to existing

information and the highly localized nature of air quality responses associated with HAP and

22 Table 4-3 presents the methane-related climate effects based on SC-CH4 at discount rates of 2.5, 3, and 5 percent.



VOC reductions.23 In this chapter, we provide a qualitative assessment of the health benefits

associated with reducing exposure to these pollutants, as well as visibility impairment and

ecosystem benefits. Table 4-1 summarizes the quantified and unquantified benefits in this

analysis.

Table 4-1 Climate and Human Health Effects of Emission Reductions from this Rule

Category Specific Effect

Effect Has

Been

Quantified

Effect Has

Been

Monetized

More

Information

Improved Environment

Reduced climate

effects

Global climate impacts from methane and

carbon dioxide (CO2)

-1

Marten et al.

(2014), SC-CO2

TSDs

Other climate impacts (e.g., ozone, black

carbon, aerosols, other impacts)

- -

IPCC, Ozone ISA,

PM ISA2

Improved Human Health

Reduced incidence of

premature mortality

from exposure to

PM2.5

Adult premature mortality based on cohort

study estimates and expert elicitation estimates

(age >25 or age >30)

- - PM ISA3

Infant mortality (age <1) - - PM ISA3

Reduced incidence of

morbidity from

exposure to PM2.5

Non-fatal heart attacks (age > 18) - - PM ISA3

Hospital admissions-respiratory (all ages) - - PM ISA3

Hospital admissions-cardiovascular (age >20) - - PM ISA3

Emergency room visits for asthma (all ages) - - PM ISA3

Acute bronchitis (age 8-12) - - PM ISA3

Lower respiratory symptoms (age 7-14) - - PM ISA3

Upper respiratory symptoms (asthmatics age 9-

11)

- - PM ISA3

Asthma exacerbation (asthmatics age 6-18) - - PM ISA3

Lost work days (age 18-65) - - PM ISA3

Minor restricted-activity days (age 18-65) - - PM ISA3

Chronic Bronchitis (age >26) - - PM ISA3

Emergency room visits for cardiovascular

effects (all ages)

- - PM ISA3

Strokes and cerebrovascular disease (age 50-

79)

- - PM ISA3

Other cardiovascular effects (e.g., other ages) - - PM ISA2

Other respiratory effects (e.g., pulmonary

function, non-asthma ER visits, non-bronchitis

chronic diseases, other ages and populations)

- - PM ISA2

23 Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the

effect those emissions have on ambient PM2.5 levels and the health effects associated with PM2.5 exposure (Fann,

Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the

geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled

in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in

that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about

the relationship between VOC emissions and PM2.5 and the highly localized nature of air quality responses

associated with VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton

estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

4-3

Category Specific Effect

Effect Has

Been

Quantified

Effect Has

Been

Monetized

More

Information

Reproductive and developmental effects (e.g.,

low birth weight, pre-term births, etc)

- - PM ISA2,4

Cancer, mutagenicity, and genotoxicity effects - - PM ISA2,4

Reduced incidence of

mortality from

exposure to ozone

Premature mortality based on short-term study

estimates (all ages)

- - Ozone ISA3

Premature mortality based on long-term study

estimates (age 30-99)

- - Ozone ISA3

Reduced incidence of

morbidity from

exposure to ozone

Hospital admissions-respiratory causes (age >

65)

- - Ozone ISA3

Hospital admissions-respiratory causes (age

<2)

- - Ozone ISA3

Emergency department visits for asthma (all

ages)

- - Ozone ISA3

Minor restricted-activity days (age 18-65) - - Ozone ISA3

School absence days (age 5-17) - - Ozone ISA3

Decreased outdoor worker productivity (age

18-65)

- - Ozone ISA3

Other respiratory effects (e.g., premature aging

of lungs)

- - Ozone ISA2

Cardiovascular and nervous system effects - - Ozone ISA2

Reproductive and developmental effects - - Ozone ISA2,4

Reduced incidence of

morbidity from

exposure to HAP

Effects associated with exposure to hazardous

air pollutants such as benzene

- - ATSDR, IRIS2,3

Improved Environment

Reduced visibility

impairment

Visibility in Class 1 areas - - PM ISA3

Visibility in residential areas - - PM ISA3

Reduced effects from

PM deposition

(organics)

Effects on Individual organisms and

ecosystems

- - PM ISA2

Reduced vegetation

and ecosystem effects

from exposure to

ozone

Visible foliar injury on vegetation - - Ozone ISA3

Reduced vegetation growth and reproduction - - Ozone ISA3

Yield and quality of commercial forest

products and crops

- - Ozone ISA3

Damage to urban ornamental plants - - Ozone ISA2

Carbon sequestration in terrestrial ecosystems - - Ozone ISA3

Recreational demand associated with forest

aesthetics

- - Ozone ISA2

Other non-use effects Ozone ISA2

Ecosystem functions (e.g., water cycling,

biogeochemical cycles, net primary

productivity, leaf-gas exchange, community

composition)

- - Ozone ISA2

1 The global climate and related impacts of $CO_2$ and $CH_4$ emissions changes, such as sea level rise, are estimated within each

integrated assessment model as part of the calculation of the SC-$CO_2$ and SC-$CH_4$. The resulting monetized damages, which

are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes

in $CO_2$ emissions.

2 We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.

3 We assess these benefits qualitatively due to data limitations for this analysis, but we have quantified them in other analyses.

4 We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant

concerns over the strength of the association.



4.2 Emission Reductions from the Final NSPS

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a

variety of emission points for methane, VOC, and HAP, including wells, wellsites, processing

plants, compressor stations, storage equipment, and transmission and distribution lines. These

emission points are located throughout much of the country with significant concentrations in

particular regions. For example, wells and processing plants are largely concentrated in the South

Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within

areas of high population density.

In implementing this rule, emission controls may lead to reductions in ambient PM2.5 and

ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist

other areas with attaining the NAAQS. Due to the high degree of variability in the

responsiveness of ozone and PM2.5 formation to VOC emission reductions, we are unable to

determine how this rule might affect attainment status without air quality modeling data.24

Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences

worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate

the potential costs and benefits of attaining a new air quality standard nationwide based on an

array of emission control strategies for different sources.25 By contrast, the emission reductions

for implementation rules, including this rule, are generally from a specific class of wellcharacterized

sources. In general, the EPA is more confident in the magnitude and location of the

emission reductions for implementation rules rather than illustrative NAAQS analyses. Emission

reductions achieved under these and other promulgated rules will ultimately be reflected in the

baseline of future NAAQS analyses, which would reduce the incremental costs and benefits

associated with attaining future NAAQS.

24 The responsiveness of ozone and PM2.5 formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this

RIA.

25 NAAQS RIAs hypothesize, but do not predict, the control strategies States may choose to enact when

implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the

NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other

regulations that result in specific costs of control and emission reductions. However, some costs and benefits

estimated in this RIA may account for the same air quality improvements as estimated in an illustrative NAAQS

RIA.



Table 4-2 shows the direct emissions reductions anticipated for this rule, across the

regulatory options examined. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. VOC emissions are precursors to secondary formation of PM2.5 and ozone and reducing these emissions would reduce exposure to these secondary pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane generally do not depend on the location of the emission of the gas, and have global impacts. Methane is also a precursor to global background concentrations of ozone.

Table 4-2 Direct Emission Reductions across NSPS Regulatory Options in 2020 and 2025

| Pollutant | Option 1 | Option 2 (Final) | Option 3 |
| --- | --- | --- | --- |
| 2020 | | | |
| Methane (short tons/year) | 250,000 | 300,000 | 350,000 |
| VOC (short tons/year) | 130,000 | 150,000 | 160,00 |
| HAP (short tons/year) | 1,300 | 1,900 | 2,400 |
| Methane (metric tons) | 230,000 | 280,000 | 320,000 |
| Methane (million metric tons $CO_2$ Eq.) | 5.6 | 6.9 | 8.0 |
| 2025 | | | |
| Methane (short tons/year) | 390,000 | 510,000 | 610,000 |
| VOC (short tons/year) | 170,000 | 210,000 | 230,000 |
| HAP (short tons/year) | 2,700 | 3,900 | 5,000 |
| Methane (metric tons) | 360,000 | 460,000 | 550,000 |
| Methane (million metric tons $CO_2$ Eq.) | 8.9 | 11 | 14 |

## 4.3 Methane Climate Effects and Valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.



According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment

Report (AR5, 2013), changes in methane concentrations since 1750 contributed 0.48 W/m2 of forcing, which is about 17 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after $CO_2$. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions were estimated to have contributed to 0.97 W/m2 of forcing today, which is about 30 percent of the contemporaneous forcing due to historical greenhouse gas emissions.

The oil and gas category emits significant amounts of methane. The public Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 (to be published April 15, 2016) estimates 2014 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 232 MMt $CO_2$ Eq. In 2014, total methane emissions from the oil and gas industry represented 32 percent of the total methane emissions from all sources and account for about 3 percent of all $CO_2$ Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2016c).

Actions taken to comply with the NSPS are anticipated to significantly decrease methane emissions from the oil and natural gas sector in the United States. The final standards are expected to reduce methane emissions annually by about 6.9 million metric tons $CO_2$ Eq. in 2020 and by about 12 million metric tons $CO_2$ Eq. in 2025. It is important to note that the emission reductions are based upon predicted activities in 2020 and 2025; however, the EPA did not forecast sector-level emissions in 2020 and 2025 for this rulemaking. To give a sense of the magnitude of the reductions, the methane reductions estimated for 2020 are equivalent to about 2.8 percent of the methane emissions for this sector reported in the U.S. GHG Inventory for 2014 (about 232 million metric tons $CO_2$ Eq. are from petroleum and natural gas production and gas processing, transmission, and storage). Expected reductions in 2025 are equivalent to around 4.7 percent of 2014 emissions. As it is expected that emissions from this sector would increase over time, the estimates compared against the 2014 emissions would likely overestimate the percent of reductions from total emissions in 2020 and 2025.

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We calculated the global social benefits of methane emissions reductions expected from the NSPS using estimates of the social cost of methane (SC-CH4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning.

The SC-CH4 estimates applied in this analysis were developed by Marten et al. (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO2 (SC-CO2), provides important context for understanding the Marten et al. SC-CH4 estimates. Estimates of the SC-CO2 have been used by the EPA and other federal agencies to value the impacts of CO2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008. The SC-CO2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO2 emissions in a given year.

Similar the SC-CH4 includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning.

The SC-CO2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO2 estimates and recommended four global values for use in regulatory analyses. The SC-CO2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2013 update did not revisit the 2010 modeling decisions with regards to the discount rate, reference case socioeconomic and emission scenarios, and equilibrium climate sensitivity distribution. Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SC-CO2 Technical Support Document (2010 SC-CO2 TSD) provides a complete discussion of the

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methods used to develop these estimates and the current SC-CO2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).26

One key methodological aspect discussed in the SC-CO2 TSDs is the global scope of the estimates. The SC-CO2 estimates represent global measures because of the distinctive nature of the climate change, which is highly unusual in at least three respects. First, emissions of most GHGs contribute to damages around the world independent of the country in which they are emitted. The SC-CO2 must therefore incorporate the full (global) damages caused by GHG emissions to address the global nature of the problem. Second, the U.S. operates in a global and highly interconnected economy, such that impacts on the other side of the world can affect our economy. This means that the true costs of climate change to the U.S. are larger than the direct impacts that simply occur within the U.S. Third, climate change represents a classic public goods problem because each country's reductions benefit everyone else and no country can be excluded from enjoying the benefits of other countries' reductions, even if it provides no reductions itself.

In this situation, the only way to achieve an economically efficient level of emissions reductions is for countries to cooperate in providing mutually beneficial reductions beyond the level that would be justified only by their own domestic benefits. In reference to the public good nature of mitigation and its role in foreign relations, thirteen prominent academics noted that these "are compelling reasons to focus on a global SCC" (Pizer et al., 2014). In addition, the IWG recently noted that there is no bright line between domestic and global damages. Adverse impacts on other countries can have spillover effects on the United States, particularly in the areas of national security, international trade, public health and humanitarian concerns.27

The 2010 SC-CO2 TSD also noted a number of limitations to the SC-CO2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion.

Currently IAMs do not assign value to all of the important physical, ecological, and economic

26 Both the 2010 SC-CO2 TSD and the current SC-CO2 TSD are available at:

<https://www.whitehouse.gov/omb/oira/social-cost-of-carbon>

27 See Response to Comments: Social Cost of Carbon For Regulatory Impact Analysis Under Executive Order

12866, July 2015, page 31, at <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-tocomments-

final-july-2015.pdf>



impacts of climate change recognized in the climate change literature due to a lack of precise

information on the nature of damages and because the science incorporated into these models

understandably lags behind the most recent research.28 The limited amount of research linking

climate impacts to economic damages makes the modeling exercise even more difficult. These

individual limitations do not all work in the same direction in terms of their influence on the SCCO2

estimates, though taken together they suggest that the SC-CO2 estimates are likely

conservative. In particular, the IPCC Fourth Assessment Report (2007), which was the most

current IPCC assessment available at the time of the IWG's 2009-2010 review, concluded that

"It is very likely that [SC-CO2 estimates] underestimate the damage costs because they cannot

include many non-quantifiable impacts." Since then, the peer-reviewed literature has continued

to support this conclusion. For example, the IPCC Fifth Assessment report (2014) observed that

SC-CO2 estimates continue to omit various impacts, such as "the effects of the loss of

biodiversity among pollinators and wild crops on agriculture."29 Nonetheless, these estimates and

the discussion of their limitations represent the best available information about the social

benefits of CO2 reductions to inform benefit-cost analysis. The new versions of the models offer

some improvements in these areas, although further work is warranted.

Accordingly, the EPA and other agencies continue to engage in research on modeling and

valuation of climate impacts with the goal to improve these estimates. The EPA and other

agencies also continue to consider feedback on the SC-CO2 estimates from stakeholders through

a range of channels, including public comments on Agency rulemakings that use the SC-CO2 in supporting analyses and through regular interactions with stakeholders and research analysts

implementing the SC-CO2 methodology used by the IWG. In addition, OMB sought public

28 Climate change impacts and social cost of greenhouse gases modeling is an area of active research. For example,

see: (1) Howard, Peter, "Omitted Damages: What's Missing from the Social Cost of Carbon." March 13, 2014,

http://costofcarbon.org/files/Omitted_Damages_Whats_Missing_From_the_Social_Cost_of_Carbon.pdf; and (2)

Electric Power Research Institute, "Understanding the Social Cost of carbon: A Technical Assessment," October

2014, www.epri.com.

29 Oppenheimer, M., M. Campos, R.Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: Emergent

risks and key vulnerabilities. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global

and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the

Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D.

Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy,

S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United

Kingdom and New York, NY, USA, pp. 1039-1099.



comment on the approach used to develop the SC-CO2 estimates through a separate comment

period and published a response to those comments in 2015.30

After careful evaluation of the full range of comments submitted to OMB, the IWG

continues to recommend the use of the SC-CO2 estimates in regulatory impact analysis. With the

release of the response to comments, the IWG announced plans in July 2015 to obtain expert

independent advice from the National Academies of Sciences, Engineering and Medicine to

ensure that the SC-CO2 estimates continue to reflect the best available scientific and economic

information on climate change.31 The Academies then convened a committee, "Assessing

Approaches to Updating the Social Cost of Carbon," (Committee) that is reviewing the state of

the science on estimating the SC-CO2, and will provide expert, independent advice on the merits

of different technical approaches for modeling and highlight research priorities going forward.

While the Committee's review focuses on the SC-CO2 methodology, recommendations on how

to update many of the underlying modeling assumptions will also likely pertain to the SC-CH4 estimates. EPA will evaluate its approach based upon any feedback received from the Academies' panel.

To date, the Committee has released an interim report, which recommended against doing a near term update of the SC-CO2 estimates. For future revisions, the Committee recommended the IWG move efforts towards a broader update of the climate system module consistent with the most recent, best available science, and also offered recommendations for how to enhance the discussion and presentation of uncertainty in the SC-CO2 estimates. Specifically, the Committee recommended that "the IWG provide guidance in their technical support documents about how [SC-CO2] uncertainty should be represented and discussed in individual regulatory impact analyses that use the [SC-CO2]" and that the technical support document for each update of the estimates present a section discussing the uncertainty in the overall approach, in the models used, and uncertainty that may not be included in the estimates.32 At the time of this writing, the IWG

30 See <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf>.

31 The Academies' review will be informed by public comments and focus on the technical merits and challenges of potential approaches to improving the SC-CO2 estimates in future updates.See <https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions>.

32 National Academies of Sciences, Engineering, and Medicine. (2016). Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update. Committee on Assessing Approaches to Updating the Social Cost of Carbon, Board on Environmental Change and Society. Washington, DC: The National Academies Press. doi: 10.17226/21898. See Executive Summary, page 1, for quoted text.



is reviewing the interim report and considering the recommendations. EPA looks forward to working with the IWG to respond to the recommendations and will continue to follow IWG guidance on SC-CO2.

The four SC-CO2 estimates are: $13, $45, $67, and $130 per metric ton of CO2 emissions in the year 2020 (2012 dollars).33 The first three values are based on the average SC-CO2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. Estimates of the SC-CO2 for several discount rates are included because the literature shows that the SC-CO2 is sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-$CO_2$ across all three models at a 3 percent discount rate. It is included to represent lower probability but higher -impact outcomes from climate change, which are captured further out in the tail of the SC-$CO_2$ distribution, and while less likely than those reflected by the average SC-$CO_2$ estimates, would be much more harmful to society and therefore, are relevant to policy makers. The SC-$CO_2$ increases over time because future emissions are expected to produce larger incremental damages as economies grow and physical and economic systems become more stressed in response to greater climate change.

A challenge particularly relevant to this analysis is that the IWG did not estimate the social costs of non-$CO_2$ GHG emissions at the time the SC-$CO_2$ estimates were developed. One alternative approach to value methane impacts is to use the global warming potential (GWP) to convert the emissions to $CO_2$ equivalents which are then valued using the SC-$CO_2$ estimates. The GWP measures the cumulative radiative forcing from a perturbation of a non-$CO_2$ GHG relative to a perturbation of $CO_2$ over a fixed time horizon, often 100 years. The GWP mainly reflects differences in the radiative efficiency of gases and differences in their atmospheric lifetimes. While the GWP is a simple, transparent, and well-established metric for

33 The current version of the SC-$CO_2$ TSD is available at: <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf>. The TSDs present SC-$CO_2$ in $2007. The estimates were adjusted to 2012$ using the GDP Implicit Price Deflator (1.0804). Also available at: <http://www.bea.gov/iTable/index_nipa.cfm>. The SC-$CO_2$ values have been rounded to two significant digits. Unrounded numbers from the 2013 SCC TSD were adjusted to 2012$ and used to calculate the $CO_2$ benefits.



assessing the relative impacts of non-$CO_2$ emissions compared to $CO_2$ on a purely physical basis, there are several well-documented limitations in using it to value non-$CO_2$ GHG benefits, as discussed in the 2010 SC-CO2 TSD and previous rulemakings (e.g., U.S. EPA 2012b, 2012d).34

In particular, several recent studies found that GWP-weighted benefit estimates for methane are

likely to be lower than the estimates derived using directly modeled social cost estimates for

these gases (Marten and Newbold, 2012; Marten et al. 2014; and Waldhoff et al al. 2014). Gas

comparison metrics, such as the GWP, are designed to measure the impact of non-CO2 GHG

emissions relative to CO2 at a specific point along the pathway from emissions to monetized

damages (depicted in Figure 4-1), and this point may differ across measures.

Source: Marten et al. 2014

Figure 4-1 Path from GHG Emissions to Monetized Damages

The GWP is not ideally suited for use in benefit-cost analyses to approximate the social

cost of non-CO2 GHGs because it ignores important nonlinear relationships beyond radiative

forcing in the chain between emissions and damages. These can become relevant because gases

have different lifetimes and the SC-CO2 takes into account the fact that marginal damages from

an increase in temperature are a function of existing temperature levels. Another limitation of gas

comparison metrics for this purpose is that some environmental and socioeconomic impacts are

not linked to all of the gases under consideration, or radiative forcing for that matter, and will

therefore be incorrectly allocated. For example, the economic impacts associated with increased

agricultural productivity due to higher atmospheric CO2 concentrations included in the SC-CO2

would be incorrectly allocated to methane emissions with the GWP-based valuation approach.

Also of concern is the fact that the assumptions made in estimating the GWP are not

consistent with the assumptions underlying SC-CO2 estimates in general, and the SC-CO2

estimates developed by the IWG more specifically. For example, the 100-year time horizon

usually used in estimating the GWP is less than the approximately 300-year horizon the IWG

34 See also Reilly and Richards, 1993; Schmalensee, 1993; Fankhauser, 1994; Marten and Newbold, 2012.



used in developing the SC-CO2 estimates. The GWP approach also treats all impacts within the

time horizon equally, independent of the time at which they occur. This is inconsistent with the role of discounting in economic analysis, which accounts for a basic preference for earlier over

later gains in utility and expectations regarding future levels of economic growth. In the case of

methane, which has a relatively short lifetime compared to $CO_2$, the temporal independence of

the GWP could lead the GWP approach to underestimate the SC-$CH_4$ with a larger downward

bias under higher discount rates (Marten and Newbold, 2012).35

The EPA sought public comments on the valuation of non-$CO_2$ GHG impacts in previous

rulemakings (e.g., U.S. EPA 2012b, 2012d). In general, the commenters strongly encouraged the

EPA to incorporate the monetized value of non-$CO_2$ GHG impacts into the benefit cost analysis,

however they noted the challenges associated with the GWP-approach, as discussed above, and

encouraged the use of directly-modeled estimates of the SC-$CH_4$ to overcome those challenges.

The EPA had cited several researchers that had directly estimated the social cost of non-

$CO_2$ emissions using IAMs but noted that the number of such estimates was small compared to

the large number of SC-$CO_2$ estimates available in the literature. The EPA found considerable

variation among these published estimates in terms of the models and input assumptions they

employ (U.S. EPA, 2012d)36. These studies differed in the emissions perturbation year, employed

a wide range of constant and variable discount rate specifications, and considered a range of

baseline socioeconomic and emissions scenarios that have been developed over the last 20 years.

Furthermore, at the time, none of the other published estimates of the social cost of non-$CO_2$

GHG were consistent with the SC-$CO_2$ estimates developed by the IWG, and most were likely

underestimates due to changes in the underlying science since their publication.

Therefore, the EPA concluded in those rulemaking analyses that the GWP approach

would serve as an interim method of analysis until directly modeled social cost estimates for

non-$CO_2$ GHGs, consistent with the SC-$CO_2$ estimates developed by the IWG, were developed.

35 We note that the truncation of the time period in the GWP calculation could lead to an overestimate of SC-$CH_4$ for

near term perturbation years when the SC-$CO_2$ is based on a sufficiently low or steeply declining discount rate.

36 The researchers cited U.S. EPA 2012d include: Fankhauser (1994); Kandlikar (1995); Hammitt et al. (1996); Tol

et al. (2003); Tol (2004); and Hope and Newberry (2006).

The EPA presented GWP-weighted estimates in sensitivity analyses rather than the main benefitcost

analyses.37

Since then, a paper by Marten et al. (2014) provided the first set of published SC-CH4

estimates in the peer-reviewed literature that are consistent with the modeling assumptions

underlying the SC-CO2 estimates.38 Specifically, the estimation approach Marten et al. used

incorporated the same set of three IAMs, five socioeconomic and emissions scenarios,

equilibrium climate sensitivity distribution, three constant discount rates, and aggregation

approach used by the IWG to develop the SC-CO2 estimates. The aggregation method involved

distilling the 45 distributions of the SC-CH4 produced for each emissions year into four

estimates: the mean across all models and scenarios using a 2.5 percent, 3 percent, and 5 percent

discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using

a 3 percent discount rate. Marten et al. also used the same rationale as the IWG to develop global

estimates of the SC-CH4, given that methane is a global pollutant.

In addition, the atmospheric lifetime and radiative efficacy of methane used by Marten et

al. is based on the estimates reported by the IPCC in their Fourth Assessment Report (AR4,

2007), including an adjustment in the radiative efficacy of methane to account for its role as a

precursor for tropospheric ozone and stratospheric water. These values represent the same ones

used by the IPCC in AR4 for calculating GWPs. At the time Marten et al. developed their

estimates of the SC-CH4, AR4 was the latest assessment report by the IPCC. The IPCC updates

GWP estimates with each new assessment, and in the most recent assessment, AR5, the latest

estimate of the methane GWP ranged from 28-36, compared to a GWP of 25 in AR4. The

updated values reflect a number of changes: changes in the lifetime and radiative efficiency

estimates for CO2, changes in the lifetime estimate for methane, and changes in the correction

37 For example, the 2012 New Source Performance Standards and Amendments to the National Emissions Standards

for Hazardous Air Pollutants for the Oil and Natural Gas Industry are expected to reduce methane emissions by

900,000 metric tons annually, see <http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf>.

Additionally, the 2017-2025 Light-duty Vehicle Greenhouse Gas Emission Standards and

Corporate Average

Fuel Economy Standards, promulgated jointly with the National Highway Traffic Safety Administration, is

expected to reduce methane emissions by over 100,000 metric tons in 2025 increasing to nearly 500,000 metric

tons in 2050, see <http://www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf>.

38 Marten et al. (2014) also provided the first set of SC-N2O estimates that are consistent with the assumptions

underlying the SC-CO2 estimates.



factor applied to methane's GWP to reflect the effect of methane emissions on other climatically

important substances such as tropospheric ozone and stratospheric water vapor. In addition, the

range presented in the latest IPCC report reflects different choices regarding whether to account

for climate feedbacks on the carbon cycle for both methane and CO2 (rather than just for CO2 as

was done in AR4).39,40

Marten et al. (2014) discuss these estimates, (SC-CH4 estimates presented below in Table

4-3), and compare them with other recent estimates in the literature.41 The authors noted that a

direct comparison of their estimates with all of the other published estimates is difficult, given

the differences in the models and socioeconomic and emissions scenarios, but results from three

relatively recent studies offer a better basis for comparison (see Hope (2006), Marten and

Newbold (2012), Waldhoff et al. (2014)). Marten et al. found that, in general, the SC-CH4

estimates from their 2014 paper are higher than previous estimates. The higher SC-CH4 estimates

are partially driven by the higher effective radiative forcing due to the inclusion of indirect

effects from methane emissions in their modeling. Marten et al., similar to other recent studies,

also find that their directly modeled SC-CH4 estimates are higher than the GWP-weighted

estimates. More detailed discussion of the SC-CH4 estimation methodology, results and a

comparison to other published estimates can be found in Marten et al.

39 Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment

Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor,

S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press,

Cambridge, United Kingdom and New York, NY, USA.

40 Note that this analysis uses a GWP value for methane of 25 for CO2 equivalency calculations, consistent with the

GHG emissions inventories and the IPCC Fourth Assessment Report (AR4).

41 Marten et al. (2014) estimates are presented in 2007 dollars. These estimates were adjusted for inflation using

National Income and Product Accounts Tables, Table 1.1.9, Implicit Price Deflators for Gross Domestic Product

(US Department of Commerce, Bureau of Economic Analysis), <http://www.bea.gov/iTable/index_nipa.cfm>

(1.0804) Accessed 3/3/15.



Table 4-3 Social Cost of Methane (SC-CH4), 2012 - 2050a [in 2012$ per metric ton]

(Source: Marten et al., 2014b)

| Year | SC-CH4 5 Percent Average | 3 Percent Average | 2.5 Percent Average | 3 Percent 95th percentile |
|---|---|---|---|---|
| 2012 | $430 | $1,000 | $1,400 | $2,800 |
| 2015 | $490 | $1,100 | $1,500 | $3,000 |
| 2020 | $580 | $1,300 | $1,700 | $3,500 |
| 2025 | $700 | $1,500 | $1,900 | $4,000 |
| 2030 | $820 | $1,700 | $2,200 | $4,500 |
| 2035 | $970 | $1,900 | $2,500 | $5,300 |
| 2040 | $1,100 | $2,200 | $2,800 | $5,900 |
| 2045 | $1,300 | $2,500 | $3,000 | $6,600 |
| 2050 | $1,400 | $2,700 | $3,300 | $7,200 |

a The values are emissions-year specific and are defined in real terms, i.e., adjusted for inflation using the GDP

implicit price deflator.

b The estimates in this table have been adjusted to reflect the minor technical corrections to the SC-CO2 estimates

described above. See Corrigendum to Marten et al. (2014) for more details

<http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550 >.

The application of directly modeled estimates from Marten et al. (2014) to benefit-cost

analysis of a regulatory action is analogous to the use of the SC-CO2 estimates. Specifically, the

SC-$CH_4$ estimates in Table 4-3 are used to monetize the benefits of reductions in methane emissions expected as a result of the rulemaking. Forecasted changes in methane emissions in a given year, expected as a result of the regulatory action, are multiplied by the SC-$CH_4$ estimate for that year. To obtain a present value estimate, the monetized stream of future non-$CO_2$ benefits are discounted back to the analysis year using the same discount rate used to estimate the social cost of the non-$CO_2$ GHG emission changes. In addition, the limitations for the SC$CO_2$ estimates discussed above likewise apply to the SC-$CH_4$ estimates, given the consistency in the methodology.

In early 2015, the EPA conducted a peer review of the application of the Marten et al. (2014) non-$CO_2$ social cost estimates in regulatory analysis and received responses that supported this application.42 Three reviewers considered seven charge questions that covered

42 For a copy of the peer review responses, see Docket ID EPA-HQ-OAR-2010-0505-5016. Also available at <https://cfpub.epa.gov/si/si_public_pra_view.cfm?dirEntryID=291976> (see "SCCH4 EPA PEER REVIEW FILES.PDF").



issues such as the EPA's interpretation of the Marten et al. estimates, the consistency of the estimates with the SC-$CO_2$ estimates, the EPA's characterization of the limits of the GWPapproach to value non-$CO_2$ GHG impacts, and the appropriateness of using the Marten et al. estimates in regulatory impact analyses. The reviewers agreed with the EPA's interpretation of Marten et al.'s estimates, generally found the estimates to be consistent with the SC-$CO_2$ estimates, and concurred with the limitations of the GWP approach, finding directly modeled estimates to be more appropriate. While outside of the scope of the review, the reviewers briefly considered the limitations in the SC-$CO_2$ methodology (e.g., those discussed earlier in this section) and noted that because the SC-$CO_2$ and SC-$CH_4$ methodologies are similar, the limitations also apply to the resulting SC-$CH_4$ estimates. Two of the reviewers concluded that use of the SC-$CH_4$ estimates developed by Marten et al. and published in the peer-reviewed literature is appropriate in RIAs, provided that the Agency discuss the limitations, similar to the discussion provided for SC-CO2 and other economic analyses. All three reviewers encouraged

continued improvements in the SC-CO2 estimates and suggested that as those improvements are

realized they should also be reflected in the SC-CH4 estimates, with one reviewer suggesting the

SC-CH4 estimates lag this process. The EPA supports continued improvement in the SC-CO2

estimates developed by the U.S. government and agrees that improvements in the SC-CO2

estimates should also be reflected in the SC-CH4 estimates. The fact that the reviewers agree that

the SC-CH4 estimates are generally consistent with the SC-CO2 estimates that are recommended

by OMB's guidance on valuing CO2 emissions reductions, leads the EPA to conclude that use of

the SC-CH4 estimates is an analytical improvement over excluding methane emissions from the

monetized portion of the benefit cost analysis.

The EPA also carefully considered the full range of public comments and associated

technical issues on the Marten et al. SC-CH4 estimates received through this rulemaking and

determined that it would continue to use the estimates in the final rulemaking analysis. Based on

the evaluation of the public comments on this rulemaking, the favorable peer review of the

Marten et al. application, and past comments urging the EPA to value non-CO2 GHG impacts in

its rulemakings, the EPA concluded that the estimates represent the best scientific information on

the impacts of climate change available in a form appropriate for incorporating the damages from

incremental methane emissions changes into regulatory analysis. The Agency has valued the

methane benefits expected from this rulemaking using the Marten et al. (2014) SC-CH4 estimates



and has included those benefits in the main benefits analysis. Please see the Response to

Comments document, section XIII-H-4, for EPA's detailed responses to the comments on

methane valuation.

The estimated methane benefits are presented in Table 4-4 below for years 2020 and

2025 across regulatory options. Applying this approach to the methane reductions estimated for

the final NSPS option (Option 2), the 2020 methane benefits vary by discount rate and range

from about $160 million to approximately $950 million; the mean SC-CH4 at the 3 percent

discount rate results in an estimate of about $360 million in 2020. The methane benefits increase for Option 2 in 2025 and likewise vary by discount rate, ranging from about $320 million to approximately $1.8 billion in that year; the mean SC-$CH_4$ at the 3-percent discount rate results in an estimate of about $690 million in 2025.

Table 4-4 Estimated Global Benefits of Methane Reductions* (in millions, 2012$)

| Discount rate and statistic | Option 1 | | Option 2 (final) | | Option 3 | |
|---|---|---|---|---|---|---|
| | 2020 | 2025 | 2020 | 2025 | 2020 | 2025 |
| Million metric tonnes of methane reduced | 0.23 | 0.36 | 0.28 | 0.46 | 0.32 | 0.55 |
| Million metric tonnes of $CO_2$ Eq. | 5.6 | 8.9 | 6.9 | 11 | 8.0 | 14 |
| 5% (average) | $130 | $250 | $160 | $320 | $190 | $390 |
| 3% (average) | $290 | $540 | $360 | $690 | $420 | $840 |
| 2.5% (average) | $390 | $690 | $480 | $890 | $560 | $1,100 |
| 3% (95th percentile) | $780 | $1,400 | $950 | $1,800 | $1,100 | $2,200 |

*The SC-$CH_4$ values are dollar-year and emissions-year specific. SC-$CH_4$ values represent only a partial accounting of climate impacts.

The vast majority of this rule's climate-related benefits are associated with methane reductions, but some climate-related impacts are expected from the rule's secondary air impacts. The secondary impacts are discussed in Section 4.7.

Methane is also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2013). Approximately 40 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (HTAP, 2010). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (HTAP, 2010). Unlike $NO_X$ and VOCs, which affect ozone concentrations regionally and at time scales of hours to days, methane emissions



affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime (HTAP, 2010). Reducing methane emissions, therefore, can reduce global background ozone concentrations, human exposure to ozone, and the incidence of ozone-related

health effects (West et al., 2006, Anenberg et al., 2009). These benefits are global and occur in

both urban and rural areas. Reductions in background ozone concentrations can also have

benefits for agriculture and ecosystems (UNEP/WMO, 2011). Studies show that controlling

methane emissions can reduce global ozone concentrations and climate change simultaneously.

But, controlling other shorter-lived ozone precursors such as NOX, carbon monoxide, or nonmethane

VOCs have larger local health benefits from greater reductions in local ozone

concentrations (West and Fiore, 2005; West et al., 2006; Fiore et al., 2008; Dentener et al., 2005;

Shindell et al., 2005, 2012; UNEP/WMO, 2011). The health, welfare, and climate effects

associated with ozone are described in the preceding sections.

A paper was published in the peer-reviewed scientific literature that presented a range of

estimates of the monetized ozone-related mortality benefits of reducing methane emissions

(Sarofim et al. 2015). For example, under their base case assumptions using a 3% discount rate,

Sarofim et al. find global ozone-related mortality benefits of methane emissions reductions to be

$790 per tonne of methane in 2020, with 10.6%, or $80, of this amount resulting from mortality

reductions in the United States. The methodology used in this study is consistent in some (but

not all) aspects with the modeling underlying the SC-CO2 and SC-CH4 estimates discussed

above, and required a number of additional assumptions such as baseline mortality rates and

mortality response to ozone concentrations. The proposal requested comment on the application

of the Sarofim et al. (2015) for this benefits analysis as an approach to estimating the ozone

related mortality benefits resulting from the methane reductions expected from this rulemaking.

Some commenters objected to the inclusion of these benefits because they argue that methane is

not a VOC, whereas one commenter agreed that there is a connection between methane

emissions, higher ozone levels, and therefore human mortality. While the EPA does consider the

methane impacts on ozone to be important, there remain unresolved questions regarding several

methodological choices involved in applying the Sarofim et al. (2015) approach in the context of

an EPA benefits analysis, and therefore the EPA is not including a quantitative analysis of this

effect in this rule at this time.

## 4.4 VOC as a PM2.5 Precursor

This rulemaking would reduce emissions of VOC, which are a precursor to PM2.5. Most VOC emitted are oxidized to $CO_2$ rather than to PM, but a portion of VOC emission contributes to ambient PM2.5 levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce PM2.5 formation, human exposure to PM2.5, and the incidence of PM2.5-related health effects. However, we have not quantified the PM2.5-related benefits in this analysis.

Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory, it is unlikely this sector has a large contribution to ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform the air quality modeling needed to quantify PM2.5 benefits associated with reducing VOC emissions for this rule. Due to the high degree of variability in the responsiveness of PM2.5 formation to VOC emission reductions, we are unable to estimate the effect that reducing VOC will have on ambient PM2.5 levels without air quality modeling. However, we provide the discussion below for context regarding findings from previous modeling.

### 4.4.1 PM2.5 Health Effects and Valuation

Reducing VOC emissions would reduce PM2.5 formation, human exposure, and the incidence of PM2.5-related health effects. Reducing exposure to PM2.5 is associated with significant human health benefits, including avoiding mortality and respiratory morbidity.

Researchers have associated PM2.5- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, the EPA generally quantifies several health effects associated with



exposure to PM2.5 (e.g., U.S. EPA (2011g)). These health effects include premature mortality for adults and infants; cardiovascular morbidity, such as heart attacks; respiratory morbidity, such as asthma attacks and acute and chronic bronchitis; which result in hospital and ER visits, lost work days, restricted activity days, and respiratory symptoms. Although the EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to PM2.5 is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

When the EPA quantifies PM2.5-related benefits, the agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of PM2.5 in the underlying epidemiology studies.

Fann, Fulcher, and Hubbell (2009) examined how the monetized benefit-per-ton estimates of reducing ambient PM2.5 varies by the location of the emission reduction, the type of source emitting the precursor, and the specific precursor controlled. This study employed a reduced form air quality model to estimate changes in ambient PM2.5 from reducing 12 different combinations of precursor emissions and emission sources, including reducing directly emitted carbonanecous particles, nitrogen oxides, sulfur oxides, ammonia, and VOCs for nine urban areas and nationwide. For each precursor/source combination in each location, the study authors then estimated the total monetized health benefits associated with the PM2.5 change and divided these benefits by the corresponding emissions changes to generate benefit-per-ton estimates.The

estimates from this study can provide general context for the unquantified VOC benefits in this rulemaking. Specifically, Fann, Fulcher, and Hubbell (2009) found that the monetized benefitper-ton of reducing VOC emissions ranged from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOC, from the Laden et al. (2006) mortality function (based on the Harvard Six Cities study, a large cohort epidemiology study in the Eastern U.S., an analysis year of 2015, a 3 percent discount



rate, and 2006$). Additional benefit-per-ton estimates are available from this dataset using alternate assumptions regarding the relationship between PM2.5 exposure and premature mortality from empirical studies and those supplied by experts (e.g., Pope et al., 2002; Laden et al., 2006; Roman et al., 2008). The EPA generally presents a range of benefits estimates derived from the American Cancer Society cohort (e.g., Pope et al., 2002; Krewski et al., 2009) to the Harvard Six Cities cohort (e.g., Laden et al., 2006; Lepuele et al., 2012) because the studies are both welldesigned and extensively peer reviewed. The EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. As shown in Table 4-5, the range of VOC benefits that reflect the range of epidemiology studies and the range of the urban areas is $300 to $7,500 per ton of VOC reduced (2012$).43 Since these estimates were presented in the 2012 Oil and Gas NSPS RIA (U.S. EPA, 2012b), we updated our methods to apply more recent epidemiological studies for these cohorts (i.e., Krewski et al., 2009; Lepuele et al., 2012) as well as additional updates to the morbidity studies and population data.44 Because these updates would not lead to significant changes in the benefit-per-ton estimates for VOC, we have not updated them here.

While these ranges of benefit-per-ton estimates provide general context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors.

Coupled with the larger uncertainties about the relationship between VOC emissions and PM2.5,

these factors lead the EPA to conclude that the available VOC benefit per ton estimates are not

appropriate to calculate monetized benefits of this rule, even as a bounding exercise.

43 We also converted the estimates from Fann, Fulcher, and Hubbell (2009) to 2012$ and applied EPA's current

value of a statistical life (VSL) estimate. For more information regarding EPA's current VSL estimate, please see

Section 5.6.5.1 of the RIA for the PM NAAQS RIA (U.S. EPA, 2012c). EPA continues to work to update its

guidance on valuing mortality risk reductions.

44 For more information regarding these updates, please see Section 5.3 of the RIA for the final PM NAAQS (U.S.

EPA, 2012c).



Table 4-5 Monetized Benefits-per-Ton Estimates for VOC in 9 Urban Areas and Nationwide based on Fann, Fulcher, and

Hubbell (2009) in (2012$)

Area

Pope et al.

(2002)

Laden et al.

(2006)

Expert

A

Expert

B

Expert

C

Expert

D

Expert

E

Expert

F

Expert

G

Expert

H

Expert

I

Expert

J

Expert

K

Expert

L

Atlanta $660 $1,600 $1,700 $1,300 $1,300 $920 $2,100 $1,200 $780 $980 $1,300 $1,000 $260 $1,000

Chicago $1,600 $4,000 $4,200 $3,300 $3,200 $2,300 $5,300 $3,000 $1,900 $2,400 $3,200 $2,600 $640 $2,500

Dallas $320 $790 $830 $650 $630 $450 $1,000 $580 $380 $480 $630 $510 $130 $490

Denver $770 $1,900 $2,000 $1,500 $1,500 $1,100 $2,400 $1,400 $910 $1,100 $1,500 $1,200 $300 $910

NYC/ Philadelphia $2,300 $5,600 $5,900 $4,600 $4,500 $3,200 $7,300 $4,100 $2,700 $3,400 $4,500 $3,600 $890 $3,300

Phoenix $1,100 $2,700 $2,800 $2,200 $2,100 $1,500 $3,500 $2,000 $1,300 $1,600 $2,100 $1,700 $420 $1,600

Salt Lake $1,400 $3,300 $3,500 $2,700 $2,700 $1,900 $4,400 $2,500 $1,600 $2,000 $2,700 $2,200 $570 $2,100

San Joaquin $3,100 $7,500 $7,900 $6,100 $6,000 $4,300 $9,700 $5,500 $3,600 $4,500 $6,000 $4,900 $1,400 $4,600

Seattle $300 $730 $770 $570 $590 $420 $950 $540 $350 $440 $580 $470 $120 $350

National average $1,300 $3,200 $3,400 $2,600 $2,600 $1,800 $4,200 $2,300 $1,500 $1,900 $2,500 $2,100 $520 $1,900

* The estimates in this table provide general context regarding the potential magnitude of monetized benefits from reducing VOC emissions, but these urban

areas were not chosen based on the locations of VOC emissions from the oil and gas sector. Coupled with other uncertainties, these VOC benefit-per-ton

estimates are not appropriate to calculate monetized benefits of this rule. These estimates assumed a 50 percent reduction in VOC emissions, an analysis year

of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been adjusted from Fann, Fulcher, and Hubbell

(2009) to reflect a more recent currency year and the EPA's current VSL estimate. However, these estimates have not been updated to reflect recent

epidemiological studies for mortality studies, morbidity studies, or population data. Using a discount rate of 7 percent, the benefit-per-ton estimates would be

approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase theVOC benefit-per-ton estimates by approximately 13

percent. Assuming a 25 percent reduction in VOC emissions would decrease the VOC benefit-per-ton estimates by 13 percent. The EPA generally presents a

range of benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.



4.4.2 Organic PM Welfare Effects

According to the previous residual risk assessment for this sector (U.S. EPA, 2012a),

persistent and bioaccumulative HAP reported as emissions from oil and gas operations include

polycyclic organic matter (POM). POM defines a broad class of compounds that includes

polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are

associated with deposition of organic particles, including persistent organic pollutants, and PAHs

(U.S. EPA, 2009a). This summary is from section 6.6.1 of the 2012 PM NAAQS RIA (U.S.

EPA, 2012c).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna.

The uptake of organics depends on the plant species, site of deposition, physical and chemical

properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a).

PAHs can accumulate to high enough concentrations in some coastal environments to pose an

environmental health threat that includes cancer in fish populations, toxicity to organisms living

in the sediment and risks to those (e.g., migratory birds) that consume these organisms.

Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments

of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal

and organic component of storm water runoff. This atmospherically-associated pollutant burden

can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to

aquatic food webs was demonstrated in high elevation mountain lakes with no other

anthropogenic contaminant sources.

The Western Airborne Contaminants Assessment Project (WACAP) is the most

comprehensive database on contaminant transport and PM depositional effects on sensitive

ecosystems in the Western U.S. (Landers et al., 2008). In this project, the transport, fate, and

ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from

2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer

needles, and fish) in eight core national parks. The study concluded that bioaccumulation of

semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient

in PM deposition exists with greater accumulation in higher altitude areas, and contaminants

accumulate in proximity to individual agriculture and industry sources, which is counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

### 4.4.3 Visibility Effects

Reducing secondary formation of PM2.5 from VOC emissions would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2011a; U.S. EPA, 2011g; U.S. EPA, 2012c) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

### 4.5 VOC as an Ozone Precursor

This rulemaking would reduce emissions of VOC, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NOX), react in the presence of sunlight. In urban areas, compounds representing all classes of VOC are important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2013). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a, 2014b). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a

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benefit-per-ton estimate, particularly for sectors with substantial new growth. Third, the impact

of reducing VOC emissions is spatially heterogeneous depending on local air chemistry. Urban

areas with a high population concentration are often VOC-limited, which means that ozone is

most effectively reduced by lowering VOC. Rural areas and downwind suburban areas are often

NOX-limited, which means that ozone concentrations are most effectively reduced by lowering

NOX emissions, rather than lowering emissions of VOC. Between these areas, ozone is relatively

insensitive to marginal changes in both NOX and VOC.

Due to data limitations regarding potential locations of new and modified sources

affected by this rulemaking, we did not perform air quality modeling for this rule needed to

quantify the ozone benefits associated with reducing VOC emissions. Due to the high degree of

variability in the responsiveness of ozone formation to VOC emission reductions and data

limitations regarding the location of new and modified wellsites, we are unable to estimate the

effect that reducing VOC will have on ambient ozone concentrations without air quality

modeling.

4.5.1 Ozone Health Effects and Valuation

Reducing ambient ozone concentrations is associated with significant human health

benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Researchers have

associated ozone exposure with adverse health effects in numerous toxicological, clinical and

epidemiological studies (U.S. EPA, 2013). When adequate data and resources are available, EPA

generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA,

2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma

attacks, hospital and emergency department visits, school loss days, as well as premature

mortality. The scientific literature is also suggestive that exposure to ozone is also associated

with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOC from

industrial boilers resulted in \$3.6 to \$15 million (2008\$) of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).45 After updating the currency year to 2012$, this implies a

45 While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NOX

emissions, which make it difficult to isolate the benefits attributable to VOC reductions.



benefit-per-ton for ozone of $260 to $1,100 per ton of VOC reduced. Since EPA conducted the analysis of industrial boilers, EPA published the Integrated Science Assessment for Ozone (U.S. EPA, 2013), the Health Risk and Exposure Assessment for Ozone (U.S. EPA, 2014a), and the RIA for the proposed Ozone NAAQS (U.S. EPA, 2014b). Therefore, the ozone mortality studies applied in the boiler analysis, while current at that time, do not reflect the most updated literature available. The selection of ozone mortality studies used to estimate benefits in RIAs was revisited in the RIA for the proposed Ozone NAAQS. Applying the more recent studies would lead to benefit-per-ton estimates for ozone within the range shown here. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those estimates to provide useful estimates of the monetized benefits of this rule, even as a bounding exercise.

4.5.2 Ozone Vegetation Effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2013). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

4.5.3 Ozone Climate Effects

Ozone is a well-known short-lived climate forcing greenhouse gas (GHG) (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). The IPCC AR5 estimated that the contribution to current warming



levels of increased tropospheric ozone concentrations resulting from human methane, $NO_x$, and VOC emissions was 0.5 $W/m^2$, or about 30 percent as large a warming influence as elevated $CO_2$ concentrations. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

4.6 Hazardous Air Pollutant (HAP) Benefits

When looking at exposures from all air toxic sources of outdoor origin across the U.S., we see that emissions declined by approximately 60 percent since 1990. However, despite this decline, the 2011 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2015).46 The levels of air toxics to which people are exposed vary depending on where they live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, the EPA conducts the NATA.47 The most recent NATA was conducted for calendar year 2011 and was released in December 2015. NATA includes four steps:

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient concentrations of air toxics across the U.S. utilizing dispersion models

3) Estimating population exposures across the U.S. utilizing exposure models

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2011 NATA, the EPA estimates that less than 1 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer

risk is about 40 in a million. Nationwide, the key pollutants that contribute most to the overall

46 The 2011 NATA is available on the Internet at http://www.epa.gov/national-air-toxics-assessment/2011-nationalair-

toxics-assessment.

47 The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting

regulatory standards. These limitations and uncertainties are discussed on the 2011 NATA website. Even so, this

modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting

regulatory priorities, and informing the decision making process. U.S. EPA. (2015) 2011 National-Scale Air

Toxics Assessment. <http://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment>.

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cancer risks are formaldehyde and benzene. 48,49 Secondary formation (e.g., formaldehyde

forming from other emitted pollutants) was the largest contributor to cancer risks, while

stationary, mobile, biogenics, and background sources contribute lesser amounts to the remaining

cancer risk.

Noncancer health effects can result from chronic,50 subchronic,51 or acute52 inhalation

exposure to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory

effects as well as effects on the immune and reproductive systems. According to the 2011

NATA, about 80 percent of the U.S. population was exposed to an average chronic concentration

of air toxics that has the potential for adverse noncancer respiratory health effects. Results from

the 2011 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

Figure 4-2 and Figure 4-3 depict the 2011 NATA estimated census tract-level

carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note

that large reductions in HAP emissions may not necessarily translate into significant reductions

in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels

of concern. For example, acetaldehyde mass emissions were more than seventeen times acrolein

emissions on a national basis in the EPA's 2011 National Emissions Inventory (NEI). However,

the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is

considerably lower than that for acetaldehyde, this results in 2011 NATA estimates of

nationwide chronic respiratory noncancer risks from acrolein being over three times that of

48 Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2011 NATA

risk estimates can be found at <http://www.epa.gov/national-air-toxics-assessment/nata-limitations>.

49 Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including

both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission

inventories) judgments can be found at <http://www.epa.gov/national-air-toxics-assessment/nata-limitations>.

50 Chronic exposure is defined in the glossary of the Integrated Risk Information System (IRIS) database

(<http://www.epa.gov/iris>) as repeated exposure by the oral, dermal, or inhalation route for more than

approximately 10 of the life span in humans (more than approximately 90 days to 2 years in typically used

laboratory animal species).

51 Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days,

up to approximately 10 of the life span in humans (more than 30 days up to approximately 90 days in typically

used laboratory animal species).

52 Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

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acetaldehyde. 53 Thus, it is important to account for the toxicity and exposure, as well as the mass

of the targeted emissions.

Figure 4-2 2011 NATA Model Estimated Census Tract Carcinogenic Risk from HAP

Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory

53 Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well

as chemical values comparisons) can be found at <http://www.epa.gov/iris>.

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Figure 4-3 2011 NATA Model Estimated Census Tract Noncancer (Respiratory) Risk

from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions

Inventory

Due to methodology and data limitations, we were unable to estimate the benefits

associated with the hazardous air pollutants that would be reduced as a result of this rule. In a

few previous analyses of the benefits of reductions in HAP, EPA has quantified the benefits of potential reductions in the incidences of cancer and noncancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) and reference concentrations (RfC) developed through risk assessment procedures. The URF is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one µg/m3 of a pollutant. These URFs are designed to be conservative, and as such, are more likely to represent the high end of



the distribution of risk rather than a best or most likely estimate of risk. An RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious noncancer health effects during a lifetime. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPASAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAP.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAP) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal).

Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP anticipated to be reduced by this rule. EPA remains committed to



improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAP are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2012a). In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. This rule is anticipated to avoid or reduce 3,400 tons of HAP in 2025. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

### 4.6.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[54,55,56] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human

54 U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: <http://www.epa.gov/iris/subst/0276.htm>.

55 International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

56 Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.



Services has characterized benzene as a known human carcinogen.[57,58] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[59,60]

4.6.2 Toluene[61]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation

exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation,

dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction,

attention deficits, and minor craniofacial and limb anomalies, in the children of women who

abused toluene during pregnancy. A substantial database examining the effects of toluene in

57 International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk

of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health

Organization, Lyon, France.

58 U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens

available at: <http://ntp.niehs.nih.gov/go/16183>.

59 Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

60 Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

61 All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene

(CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of

Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH.

Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.



subchronic and chronic occupationally exposed humans exists. The weight of evidence from

these studies indicates neurological effects (i.e., impaired color vision, impaired hearing,

decreased performance in neurobehavioral analysis, changes in motor and sensory nerve

conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.6.3 Carbonyl Sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (shortterm)

inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate

the eyes and skin in humans.62 No information is available on the chronic (long-term),

reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl

sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS

program for evidence of human carcinogenic potential.63

4.6.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral

62 Hazardous Substances Data Bank (HSDB), online database. US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at <http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1>.

63 U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0617.htm>.



cavities in male and female rats exposed to ethylbenzene via the oral route.64,65 The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).66,67 The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or

carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female

mice, which provided some evidence of carcinogenic activity in male and female mice (NTP,

1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans,

based on the NTP studies.

4.6.5 Mixed Xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in

humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild

transient eye irritation, and neurological effects.68 Other reported effects include labored

breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and

kidneys.69 Long-term inhalation exposure to xylenes in humans has been associated with a

64 Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the

Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

65 Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental

carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals

NY Acad Sci 837:15-52.

66 International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic

Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

67 National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No.

100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH

Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National

Institutes of Health. NTP, Research Triangle Park, NC.

68 U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed

Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This

material is available electronically at <http://www.epa.gov/iris/subst/0270.htm>.

69 Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is

available electronically at <http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>.

number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and

impaired motor coordination.70 EPA has classified mixed xylenes in Category D, not classifiable

with respect to human carcinogenicity.

4.6.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the

primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans

and very limited information in animals about the potential effects of n-hexane via the oral route.

Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic

(long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness,

blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral

effects, neurophysiological changes and neuropathological effects upon inhalation exposure to nhexane.

Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database

for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA

has classified hexane in Group D, not classifiable as to human carcinogenicity.71

4.6.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected

by this rule, including hydrogen sulfide ($H_2S$). Information regarding the health effects of those

compounds can be found in EPA's IRIS database.72

4.7 Secondary Air Emissions Impacts

The control techniques to meet the standards are associated with several types of secondary

emissions impacts, which may partially offset the direct benefits of this rule. Table 4-6 shows the

estimated secondary emissions associated with combustion of emissions as a result of the rule. In

70 Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is

available electronically at <http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>.

71 U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum,

Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-

25-05.pdf>.

72 U.S. EPA Integrated Risk Information System (IRIS) database is available at: <www.epa.gov/iris>.



particular, combustion-related emissions result from the control of oil well completions (i.e., exploratory and delineation wells and development wells where RECs are infeasible and pneumatic pumps and centrifugal compressors (because the requirement for these sources is to route to control). More details on the estimation of secondary impacts for each emissions category are presented in the TSD. Relative to the direct emission reductions anticipated from this rule, the magnitude of these secondary air pollutant increases is small.

Table 4-6 Increases in Secondary Air Pollutant Emissions (short tons per year)

| Emissions Category | $CO_2$ | NOX | PM | CO | THC |
|---|---|---|---|---|---|
| **2020** | | | | | |
| Total Hydraulically Fractured and Refractured Oil Well Completions | 890,000 | 460 | 17 | 2,500 | 940 |
| Fugitive Emissions | minimal | minimal | minimal | minimal | minimal |
| Pneumatic Pumps | 100,000 | 52 | 2 | 290 | 110 |
| Pneumatic Controllers | 3,900 | 2 | 0 | 11 | 4 |
| Compressors | 0 | 0 | 0 | 0 | 0 |
| Total 2020 | 1,000,000 | 510 | 19 | 2,800 | 1,100 |
| **2025** | | | | | |
| Total Hydraulically Fractured and Refractured Oil Well Completions | 950,000 | 490 | 18 | 2,700 | 1,000 |
| Fugitive Emissions | minimal | minimal | minimal | minimal | minimal |
| Pneumatic Pumps | 200,000 | 100 | 4 | 570 | 220 |
| Pneumatic Controllers | 7,800 | 4 | 0 | 22 | 8 |
| Compressors | 0 | 0 | 0 | 0 | 0 |
| Total in 2025 | 1,200,000 | 600 | 22 | 3,200 | 1,200 |

The secondary emission impacts for regulatory options are equal across the options. This result holds because the only requirements varied across the options is the frequency of survey and repair requirements. Moving from Option 1 to Option 3 increases the frequency of survey and repair under the fugitive emissions requirement, and secondary emissions from the fugitive emissions requirements are expected to be minimal.

The $CO_2$ impacts in Table 4-6 are the emissions that are expected to occur from natural gas emissions that are captured by emissions controls and combusted. However, because of the atmospheric chemistry associated with the natural gas emissions, most of the carbon in the VOCs



and $CH_4$ emissions expected in the absence of combustion-related emissions controls would have eventually oxidized forming $CO_2$ in the atmosphere and led to approximately the same long-run $CO_2$ concentrations as with controls.[73] Therefore, most of the impact of these $CO_2$ contribution to atmospheric concentrations from the flaring of $CH_4$ and VOC versus future oxidization is not additional to the impacts that otherwise would have occurred through the oxidation process.

However, there is a shift in the timing of the contribution of atmospheric $CO_2$ concentration under the policy case (in which case natural gas emissions that are captured by emissions controls are combusted). In the case of VOCs, the oxidization time in the atmosphere is relatively short, on the order of hours to months, so from a climate perspective the difference between emitting the carbon immediately as $CO_2$ during combustion or as VOCs is expected to be negligible. In the case of $CH_4$, the oxidization time is on the order of a decade, so the timing of the contribution to atmospheric $CO_2$ concertation will differ between the baseline and policy case. Because the growth rate of the SC-$CO_2$ estimates are lower than their associated discount rates, the estimated impact of $CO_2$ produced in the future via oxidized methane from these fossilbased emissions may be less than the estimated impact of $CO_2$ released immediately from combusting emissions, which would imply a small disbenefit associated with the earlier release of $CO_2$ during combustion of the $CH_4$ emissions.

In the proposal RIA, the EPA solicited comment on the appropriateness of monetizing the impact of the earlier release of $CO_2$ due to combusting methane and VOC emissions from oil and gas sites and a new potential approach for approximating this value using the SC-$CO_2$. This illustrative analysis provides a method for evaluating the estimated emissions outcomes associated with destroying one metric ton of methane by combusting fossil-based emissions at oil and gas sites (flaring) and releasing the $CO_2$ emissions immediately versus releasing them in

the future via the methane oxidation process. This illustrative analysis as provided in the

proposal demonstrated that the potential disbenefits of flaring-i.e., an earlier contribution of

$CO_2$ emissions to atmospheric concentrations -are minor compared to the benefits of flaring-

i.e., avoiding the release of and associated climate impacts from $CH_4$ emissions. EPA did not

receive any comments regarding the appropriate methodology for conducting such an analysis,

73 The social cost of methane (SC-$CH_4$) used previously in this chapter to monetize the benefits of the $CH_4$

emissions reductions does not include the impact of the carbon in $CH_4$ emissions after it oxidizes to $CO_2$.



but did receive one comment letter that voiced general support for monetizing the secondary

impacts.

In consideration of this comment while recognizing the challenges and uncertainties

related to estimation of these secondary emissions impacts for this rulemaking, EPA has

continued to examine this issue in the context of this regulatory analysis-i.e, the combusting of

fossil-based $CH_4$ at oil and gas sites-and explored ways to improve this illustrative analysis.

Specifically, EPA has modified the illustrative analysis by updating the oxidization process of

$CH_4$ to be dynamic and consistent with the modeling that underlies the SC-$CH_4$ estimates. Also

for this illustrative analysis, EPA assumed an average methane oxidation period of 12 years,

consistent with the perturbation lifetime-folding time used in IPCC AR4. The estimated

disbenefits associated with destroying one metric ton of methane through combustion of

emissions at oil and gas sites and releasing the $CO_2$ emissions in 2020 instead of being released

in the future via the methane oxidation process are found to be small relative to the benefits of

flaring. Specifically, the disbenefit is estimated to be about $15 per metric ton $CH_4$ (based on

average SC-$CO_2$ at 3 percent) or roughly one percent of the SC-$CH_4$ estimate per metric ton for

2020. The analogous estimate for 2025 is $18 per metric ton $CH_4$ or about one percent of the SCCH4

estimates per metric ton for 2025.[74,75]

74 To calculate the $CO_2$ related impacts associated the complete destruction of a ton of $CH_4$ emissions through

flaring for this illustrative application, EPA took the difference between the SC-$CO_2$

at the time of the flaring and

the discounted value of the $CO_2$ impacts assuming a geometric decay of $CH_4$ via the oxidation process with a 12

year e-folding time using the same discount rate as used to estimate the SC-$CO_2$. This value was then scaled by

44/16 to account for the relative mass of carbon contained in a ton of $CH_4$ versus a ton of $CO_2$. More specifically,

the impacts of shifting the $CO_2$ impacts are calculated as

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where tt is the year the $CH_4$ is destroyed, r is the discount rate, and T is the time horizon of the analysis.

Ideally the time horizon, T, would be sufficiently long to capture the period in which nearly all of the $CH_4$ is

expected to have been oxidized. In this analysis we use the 2100 as the time horizon, making the assumption that

the SC-$CO_2$ remains constant after 2050, the last year for which the IWG provides estimates. This methodology

improves upon the one presented at proposal by updating the oxidization process of $CH_4$

to be dynamic and

consistent with the modeling that underlies the SC-CH4 estimates.

75 The EPA also calculated these estimates using additional SC-CO2 values, specifically the average SC-CO2 at

discount rates of 5 and 2.5 percent and the 95th percentile at 3 percent. Applying these values, the estimates of

the disbenefit of releasing CO2 emissions in 2020 instead of in the future via methane oxidation ranges from $7

to $40 per metric ton CH4. The corresponding estimates for 2025 range from $9 to $51 per metric ton CH4.

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It is important to note that there are challenges and uncertainties related to this illustrative

method and estimates, which was developed to analyze secondary fossil-based emissions from

combustion. For example, these dollar per ton CH4 estimates cannot readily be applied to the

total CH4 emissions reductions presented in section 3 without additional information about the

downstream outcomes associated with the recovered gas that is not flared - e.g., whether some of

that captured gas going to be burned or leaked somewhere down the line.

The EPA will continue to study this issue and assess the complexities involved in estimating the

net emissions effects associated with secondary fossil-based emissions, including differences in

the timing of contributions to atmospheric CO2 concentrations. Given the uncertainties related to

estimating net secondary emissions effects and that the EPA has not yet received appropriate

input and review on some aspects of these calculations, the EPA is not including monetized

estimates of the impacts of small changes in the timing of atmospheric CO2 concentration

increases in the final benefits estimates in this RIA. The EPA will continue to follow the

scientific literature on this topic and update its methodologies as warranted.

Table 4-7 provides a summary of the direct and secondary emissions changes. Based on

the summary and analysis above, the net impact of both the direct and secondary impacts of this

final rule would be an improvement in ambient air quality, which would reduce potency of

greenhouse gas emissions, reduce exposure to various harmful pollutants, improve visibility

impairment, and reduce vegetation damage.

Table 4-7 Summary of Emissions Changes (short tons per year, except where noted)

Option 1 Option 2 (final) Option 3

| Pollutant | 2020 | 2025 | 2020 | 2025 | 2020 | 2025 |
| --- | --- | --- | --- | --- | --- | --- |
| Change in Direct Emissions | | | | | | |
| Methane | -250,000 | -390,000 | -300,000 | -510,000 | -350,000 | -610,000 |
| VOC | -130,000 | -170,000 | -150,000 | -210,000 | -160,000 | -230,000 |
| HAP | -1,300 | -2,700 | -1,900 | -3,900 | -2,400 | -5,000 |
| Secondary Emissions | | | | | | |
| CO2 | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 |
| NOx | 510 | 600 | 510 | 600 | 510 | 600 |
| PM | 19 | 22 | 19 | 22 | 19 | 22 |
| CO | 2,800 | 3,200 | 2,800 | 3,200 | 2,800 | 3,200 |
| THC | 1,100 | 1,200 | 1,100 | 1,200 | 1,100 | 1,200 |

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# 5 COMPARISON OF BENEFITS AND COSTS

5.1 Comparison of Benefits and Costs across Regulatory Options

Tables 5-1 though Table 5-3 present the summary of the benefits, costs, and net benefits

for the NSPS across regulatory options. Table 5-4 provides a summary of the direct and

secondary emissions changes for each regulatory option.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in

2020 and 2025 (2012$)

2020 2025

Total Monetized Benefits1 $290 million $540 million

Total Costs2 $240 million $360 million

Net Benefits3 $54 million $180 million

Non-monetized Benefits

Non-monetized climate benefits Non-monetized climate benefits

Health effects of PM2.5 and ozone

exposure from 130,000 tons of VOC

reduced

Health effects of PM2.5 and ozone

exposure from 170,000 tons of VOC

reduced

Health effects of HAP exposure from

1,300 tons of HAP reduced

Health effects of HAP exposure from

2,700 tons of HAP reduced

Health effects of ozone exposure from

250,000 tons of methane

Health effects of ozone exposure from

390,000 tons of methane

Visibility impairment Visibility impairment

Vegetation effects Vegetation effects

1 The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH4)

(model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of

this table, we show the benefits associated with the model average at a 3 percent discount rate. However, we

emphasize the importance and value of considering the benefits calculated using all four SC-CH4 estimates; the

additional benefit estimates range from $130 million to $780 million in 2020 and $250 million to $1.4 billion in

2025 for Option 1, as shown in Section 4.3. The CO2-equivalent (CO2 Eq.) methane emission reductions are 5.6

million metric tons in 2020 and 8.9 million metric tons in 2025. Also, the specific control technologies for the

NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

2 The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue

from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the

national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate

in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for

annualizing capital costs.

3 Estimates may not sum due to independent rounding.



Table 5-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Selected

Option 2 in 2020 and 2025 (2012$)

2020 2025

Total Monetized Benefits1 $360 million $690 million

Total Costs2 $320 million $530 million

Net Benefits3 $35 million $170 million

Non-monetized Benefits Non-monetized climate benefits Non-monetized climate benefits

Health effects of PM2.5 and ozone

exposure from 150,000 tons of VOC

reduced

Health effects of HAP exposure from

1,900 tons of HAP reduced

Health effects of ozone exposure from

300,000 tons of methane

Health effects of PM2.5 and ozone

exposure from 210,000 tons of VOC

reduced

Health effects of HAP exposure from

3,900 tons of HAP reduced

Health effects of ozone exposure from

510,000 tons of methane

Visibility impairment Visibility impairment

Vegetation effects Vegetation effects

1 The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH4)

(model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table,

we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the

importance and value of considering the benefits calculated using all four SC-CH4 estimates; the additional

benefit estimates range from $160 million to $950 million in 2020 and $320 million to $1.8 billion in 2025 for

Option 2, as shown in Section 4.3. The CO2-equivalent (CO2 Eq.) methane emission reductions are 6.9 million

metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the NSPS are

anticipated to have minor secondary disbenefits. See Section 4.7 for details.

2 The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue

from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the

national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate

in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for

annualizing capital costs.

3 Estimates may not sum due to independent rounding.



Table 5-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in

2020 and 2025 (2012$)

2020 2025

Total Monetized Benefits1 $420 million $840 million

Total Costs2 $490 million $880 million

Net Benefits3 -$75 million -$38 million

Non-monetized Benefits

Non-monetized climate benefits Non-monetized climate benefits

Health effects of PM2.5 and ozone

exposure from 160,00 tons of VOC

reduced

Health effects of PM2.5 and ozone

exposure from 230,000 tons of VOC

reduced

Health effects of HAP exposure from

2,400 tons of HAP reduced

Health effects of HAP exposure from

5,000 tons of HAP reduced

Health effects of ozone exposure from

350,000 tons of methane

Health effects of ozone exposure from

610,000 tons of methane

Visibility impairment Visibility impairment

Vegetation effects Vegetation effects

1 The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH4)

(model average at 2.5 percent, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table,

we show the benefits associated with the model average at a 3 percent discount rate. However, we emphasize the

importance and value of considering the benefits calculated using all four SC-CH4 estimates; the additional

benefit estimates range from $190 million to $1.1 billion in 2020 and $390 million to $2.2 billion in 2025 for this

more stringent option, as shown in Section 4.3. The CO2-equivalent (CO2 Eq.) methane emission reductions are 8

million metric tons in 2020 and 14 million metric tons in 2025. Also, the specific control technologies for the

NSPS are anticipated to have minor secondary disbenefits.

2 The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue

from additional natural gas recovery as a result of the NSPS. As can be seen in section 3.5.1 of the final RIA, the

national cost estimates in for this rule are not highly sensitive to the use of a 3 percent or 7 percent discount rate

in this RIA. As a result, the net benefits of the rule are not highly sensitive to choice of discount rate for

annualizing capital costs.

3 Estimates may not sum due to independent rounding.

A break-even analysis answers the question: "What would the benefits need to be for the

benefits to exceed the costs?" While a break-even approach is not equivalent to a benefits

analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the

context of previously modeled benefits. For Options 1 and 2 (final selected option), the

monetized climate benefits from methane emission reductions already exceed the costs, which

renders a break-even analysis for these options unnecessary. For Option 3, the monetized net

benefits are estimated to be -$73 million and -$37 million and the estimated VOC emission

reductions are 160,000 and 230,000 tons for 2020 and 2025, respectively. Thus, a break-even

analysis suggests that the VOC emissions would need to be valued at $460 per ton in 2020 and

$160 per ton in 2025 for the total monetized benefits of Option 3 to exceed costs, assuming that



the health benefits from HAP emission reductions and the ozone health benefits from methane emission reductions are zero. Previous assessments have shown that the PM2.5 health benefits associated with reducing VOC emissions were valued at $300 to $7,500 per ton of VOC emissions reduced in specific urban areas and ozone health benefits from reducing VOC emissions were valued at $260 to $1,100 per ton of VOC emissions reduced. These break-even estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even point is actually lower than the estimates provided above because the other pollutants each have nonzero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and PM2.5 formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

Table 5-4 Summary of Emissions Changes across Options for the NSPS in 2020 and 2025 (short tons per year, unless otherwise noted)

| | Option 1 | | Option 2 (final) | | Option 3 | |
|---|---|---|---|---|---|---|
| Pollutant | 2020 | 2025 | 2020 | 2025 | 2020 | 2025 |
| Reduction in Direct Emissions | | | | | | |
| Methane | -250,000 | -390,000 | -300,000 | -510,000 | -350,000 | -610,000 |
| VOC | -130,000 | -170,000 | -150,000 | -210,000 | -160,000 | -230,000 |
| HAP | -1,300 | -2,700 | -1,900 | -3,900 | -2,400 | -5,000 |
| Secondary Emissions | | | | | | |
| CO2 | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 | 1,000,000 | 1,200,000 |
| NOx | 510 | 600 | 510 | 600 | 510 | 600 |
| PM | 19 | 22 | 19 | 22 | 19 | 22 |
| CO | 2,800 | 3,200 | 2,800 | 3,200 | 2,800 | 3,200 |
| THC | 1,100 | 1,200 | 1,100 | 1,200 | 1,100 | 1,200 |

5.2 Uncertainties and Limitations

Throughout the RIA, we considered a number of sources of uncertainty, both quantitatively and qualitatively, regarding emissions reductions, benefits, and costs of the rule. We summarize the key elements of our discussions of uncertainty here:

• Projection methods and assumptions: As discussed in Section 3.4.2, over time, more facilities are newly established or modified in each year, and to the extent the facilities

remain in operation in future years, the total number of facilities subject to the NSPS



accumulates. The large majority of impacts of the rule (completion requirements at hydraulically fractured oil well completions and fugitive emissions requirements at wellsites) are based on projections and growth rates consistent with the drilling activity in the 2015 Annual Energy Outlook. To the extent actual drilling activities diverge from the Annual Energy Outlook projections, the projected regulatory impacts estimated in this document will diverge.

• Years of analysis: The years of analysis are 2020, to represent the near-term impacts of the rule, and 2025, to represent impacts of the rule over a longer period, as discussed in Section 3.4.2. While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to do this largely because of the limited information available on the turnover rate of emissions sources and controls. Extending the analysis beyond 2025 would introduce substantial and increasing uncertainties in projected impacts of the NSPS.

• State regulations in baseline: In preparing the impacts analysis, the EPA reviewed state regulations and permitting requirements, as discussed in Section 3.4.2. Applicable facilities in these states with similar requirements to the final NSPS are not included in the estimates of incrementally affected facilities presented in the RIA. This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements are not reflected in this RIA.

• Wellhead natural gas prices used to estimate revenues from natural gas recovery: The annualized compliance cost estimates presented in this RIA include revenue from natural gas recovery resulting from emissions reductions. As a result, national compliance costs depend the price of natural gas. The sensitivity of national compliance costs to assumptions about wellhead natural gas prices are examined in Section 3.5.2.

• Monetized methane-related climate benefits: The EPA considered the uncertainty associated with the social cost of methane (SC-CH4) estimates, which were used to calculate the global social benefits of methane emissions reductions expected from the NSPS. The modeling underlying the development of the SC-CH4 estimates, which is consistent with the modeling assumptions underlying the interagency working group's SC-CO2 estimates, addressed uncertainty in several ways. For example, the analysis addressed uncertainty in following areas: differences in model structure through an



ensemble of three integrated assessment models; sensitivity of the SC-CH4 estimates to key exogenous projections by using five different socioeconomic and emissions forecasts; and three discount rates to reflect some uncertainty about how interest rates may change over time and the possibility that climate damages are positively correlated with uncertain future economic activity. The application of four point estimates also helps reflect uncertainty. Chapter 4 of this RIA provides a comprehensive discussion about the methodology and application of the SC-CH4 as well as consideration of several types of secondary emissions impacts, which may partially offset the direct benefits of this rule.

- Non-monetized benefits: Numerous categories of health, welfare, and climate benefits are not quantified and monetized in this RIA. These unquantified benefits, including benefits from reducing emissions of methane, VOCs and HAP, are described in detail in Chapter 4.



# 6 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

## 6.1 Introduction

This section includes three sets of analyses for the final NSPS:

- Energy Markets Impacts
- Final Regulatory Flexibility Analysis
- Employment Impacts

## 6.2 Energy Markets Impacts Analysis

We use the National Energy Modeling System (NEMS) to estimate the impacts of the final NSPS on U.S. energy markets. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas.

A brief conceptual discussion about our energy markets impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and presenting results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain in production at the producer level for a given cost. For example, the analysis for the rule shows that performing reduced emissions completions on hydraulically-fractured oil wells would account for about 36 percent of the natural gas captured by emissions controls in 2020 and about 23 percent of captured natural gas in 2025. The fugitive emissions program at well sites is expected to account for about 62 percent

of the natural gas captured by emissions controls in 2020 and about 75 percent of captured

natural gas in 2025. The assumed $4/Mcf price for natural gas is the price paid to producers at

the wellhead. In the natural gas industry, production is metered at or very near to the wellhead,

and producers are paid based upon this metered production.

In the engineering cost analysis, it is necessary to estimate the expected costs and

revenues from implementing emissions controls at the unit level. Because of this, we estimate the

net costs as expected costs minus expected revenues for representative units. On the other hand,

NEMS models the profit maximizing behavior of representative project developers at a drilling

project level. The net costs of the regulation alter the expected discounted cash flow of drilling

and implementing oil and gas projects, and the behavior of the representative drillers adjusts



accordingly. While in the regulatory case natural gas drilling has become more efficient because

of the gas recovery, project developers still interact with markets for which supply and demand

are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium.

While we believe the cost savings as measured by revenues from selling recovered gas

(engineering costs) and measured by cost savings from averted production through efficiency

gains (energy economic modeling) are approximately the same, it is important to note that the

engineering cost analysis and the national-level cost estimates do not incorporate economic

feedbacks such as supply and demand adjustments.

6.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of the U.S. energy economy developed and maintained by the Energy

Information Administration of the U.S. Department of Energy (DOE). NEMS is used to produce

the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy

economy from the current year to 2040. DOE first developed NEMS in the 1980s, and the model

has undergone frequent updates and significant expansion since. DOE uses the modeling system

extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

The EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at the website: http://www.eia.gov/forecasts/aeo/.



NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel et al. 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next module after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2040. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2015.76

The RIA baseline is consistent with that of the Annual Energy Outlook 2015, which is used extensively in Section 2 in the Industry Profile.

6.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the final rule, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore and Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2014). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled.

New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern findings and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the NSPS. We are able to target additional expenditures for environmental controls required by the NSPS on new exploratory and developmental oil and gas production activities. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the rule.

76 Assumptions for the 2015 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/>.



While the oil production simulated by the OGSM is sent to the refining module (the Liquid Fuels Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and "negotiates" supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas is transported through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

6.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Regulatory costs associated with reduced emission completions for hydraulically fractured oil well completions are added to the drilling and completion costs of oil wells in the OGSM. Other regulatory costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The additional expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells or natural gas wells. We base the per well cost estimates on the engineering costs. Because we model natural gas recovery, we do not include revenues from additional product recovery in these costs. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of

drilling projects.

In general, the cost of capital in the model will implicitly capture potential barriers to obtaining additional capital financing for the industry on average. However, the model may not fully capture heterogeneity in the cost of capital across the industry, and therefore, may not fully capture distributional impacts across the industry as a result of firm specific characterisitics that cause them to have varying access to additional capital. An additional caveat to this analysis is that the modeling does not attempt to represent potential constraints on the supply of specific capital equipment, which may or may not be binding in practice.

Table 6-1 shows the incremental compliance that accrue to new drilling projects as a result of producers having to comply with the NSPS, across sources anticipated in 2020 and



2025. We estimate those costs as a function of new wells anticipated to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify whether costs will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells.

We divide the estimated compliance costs for the given emissions point by the appropriate number of expected new crude oil and natural gas wells in the year of analysis. The result yields an approximation of per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Hydraulically fractured oil well completions and fugitives at oil and natural gas well sites differ slightly from this approach. Drilling and completion costs of new hydraulically fractured oil wells are incremented by the weighted average of the cost of performing a REC with completion combustion and completion combustion alone. The resulting cost is itself weighted by the proportion of new hydraulically fractured oil wells estimated to be affected by the regulation. Meanwhile, assuming there is an average of two wells per wells site (see TSD for more details), new oil and gas wells face an increased annual cost of one-half of implementing the well site fugitive emission requirements.



Table 6-1 Per Well Costs for Environmental Controls Entered into NEMS (2012$)

| Emissions Sources/Points | Wells Applied To in NEMS | Annualized Cost per Unit (2012$) | Per Well Costs Applied in NEMS (2012$) | Natural Gas Recovery per Unit (Mcf) | Per Well Natural Gas Recovery Applied in NEMS (Mcf) |
|---|---|---|---|---|---|
| Well Completions | | | | | |
| Hydraulically Fractured Oil Well Completions | New Hydraulically Fractured Oil Wells | Variesa | $4,590 | 0 | 0 |
| Fugitive Emissions | | | | | |
| Oil Production Well Sites | New Oil Wells | $2,285 | $905 | 191c | 38 |
| Natural Gas Production Well Sites | New Gas Wells | $2,285 | $1,101 | 73 | 18 |
| Gathering and Boosting Stations | New Gas Wells | $25,050 | $284 | 1,629 | 18 |

Transmission Stations New Gas Wells $27,370 $13 1,673 1

Storage Facilities New Gas Wells $42,093 $25 5,899 3

Reciprocating Compressors

Transmission Stations New Gas Wells $1,748 $3 1,122 2

Storage Facilities New Gas Wells $2,077 $4 1,130 2

Centrifugal Compressors

Storage Facilities New Gas Wells $114,146 $0 0 0

Pneumatic Controllers -

Transmission and Storage Stations New Gas Wells $25 $0 144 2

Pneumatic Pumps

Well Sites New Wells $774 $15 0 0

Reporting and Recordkeeping New Wells $6,200,000b $154 0 0

a Since compliance costs vary across hydraulically fractured oil well completions, this table uses the weighted average costs by completion cost type.

b Reporting and recordkeeping costs are assumed to be equally allocated across all new wells.

c Natural gas recovery at oil well sites is the weighted average of the recovery expected from oil well sites and oil well (associated gas) sites. See TSD for detailed description of these model well sites.

6.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A result of controlling methane and VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of



implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right in an increment consistent with the technically achievable emissions transferred into the production stream as a result of the final NSPS. We enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells (Table 6-1).

6.2.3 Energy Markets Impacts

We estimate impacts to drilling activity, price and quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas. In each of these estimates, we present estimates for the baseline years of 2020 and 2025 and predicted results for 2020 and 2025 under the final rule. We also present impacts over the 2020 to 2025 period. For context, we provide estimates of production activities in 2012. With the exception of examining crude oil and natural gas trade, we focus the analysis on onshore oil and natural gas production activities in the continental (lower 48) U.S. We do this because offshore production is not affected by the NSPS and the bulk of the rule's impacts are expected to be in the continental U.S.

We first report estimates of impacts on crude oil and natural gas drilling activities and production. Table 6-2 presents estimates of successful onshore natural gas and crude oil wells drilled in the continental U.S.



Table 6-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)

| | | Projection, 2020 | | Projection, 2025 | | Projection, 2020-25 | |
|---|---|---|---|---|---|---|---|
| | 2012 | Baseline | NSPS | Baseline | NSPS | Baseline | NSPS |
| Successful Wells Drilled | | | | | | | |
| Natural Gas | 10,490 | 10,501 | 10,481 | 12,200 | 12,145 | 65,896 | 65,785 |
| Crude Oil | 28,496 | 27,455 | 27,463 | 29,244 | 29,231 | 168,768 | 168,736 |
| Total | 38,986 | 37,956 | 37,944 | 41,444 | 41,376 | 234,664 | 234,521 |
| % Change in Successful Wells Drilled from Baseline | | | | | | | |
| Natural Gas | | | 0.19% | | -0.45% | | -0.17% |
| Crude Oil | | | 0.03% | | -0.04% | | -0.02% |
| Total | | | 0.03% | | -0.16% | | -0.06% |

Results show that the final NSPS will have a relatively small impact on onshore well drilling in the lower 48 states. Drilling remains essentially unchanged in 2020, with very slight increases both oil and natural gas wells, relative to the baseline. Meanwhile, drilling of both natural gas and crude oil wells decreases slightly in 2025, relative to the baseline. The small increase in drilling in 2020 is somewhat counter-intuitive as production costs have been increased under the proposed NSPS. However, given NEMS is a dynamic, multi-period model, it is important to examine changes over multiple periods. Crude oil drilling over the 2020 to 2025 period decreases overall but by about 30 wells total, or about 0.02 percent, relative to the baseline. Natural gas drilling, over the same period remains declines by about 110 wells total, or about 0.17 percent, relative to the baseline.

Table 6-3 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS.

Table 6-3 Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

Projection, 2020 Projection, 2025 Projection, 2020-25

2012 Baseline NSPS Baseline NSPS Baseline NSPS

Domestic Production

Natural Gas (trillion cubic feet) 22.158 26.544 26.537 28.172 28.163 164.130 164.086

Crude Oil (million bbls/day) 4.597 8.031 8.031 8.027 8.028 48.084 48.086

% Change in Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

Natural Gas -0.03% -0.03% -0.03%

Crude Oil 0.00% 0.01% 0.00%



As indicated by the estimated change in the new well drilling activities, the analysis shows that the proposed NSPS will have a relatively small impact on onshore natural gas and crude oil production in the lower 48 states. Crude oil production remains essentially unchanged in 2020 and 2025 (with changes around or less than 0.01 percent in both years), relative to the baseline. While slightly increasing over the time horizon, the overall change in crude oil production is less than 0.01 percent, relative to the baseline. Natural gas production is estimated to decrease slightly during the 2020-25 period, by around 0.03 percent, relative to the baseline.

Note this analysis estimates very little change in domestic natural gas production, despite some environmental controls anticipated in response to the rule capture natural gas that would otherwise be emitted (about 16 bcf in 2020 and 27 bcf in 2025). NEMS models the adjustment of energy markets to the new slightly more costly natural gas and crude oil productive activities. At the new post-rule equilibrium, producers implementing emissions controls are still anticipated to capture and sell the captured natural gas, and this natural gas might offset other production, but not so much as to make overall production increase from the baseline projections.

Table 6-4 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states.

Table 6-4 Average Natural Gas and Crude Oil Wellhead Price (Onshore, Lower 48 States, 2012$)

| | | Projection, 2020 | | Projection, 2025 | | Projection, 2020-25 | |
|---|---|---|---|---|---|---|---|
| | 2012 | Baseline | NSPS | Baseline | NSPS | Baseline | NSPS |
| Lower 48 Average Wellhead Price | | | | | | | |
| Natural Gas (2012$ per Mcf) | 2.566 | 4.428 | 4.441 | 5.184 | 5.190 | 4.880 | 4.890 |
| Crude Oil (2012$ per barrel) | 94.835 | 73.920 | 73.918 | 85.219 | 85.218 | 79.530 | 79.527 |
| % Change in Lower 48 Average Wellhead Price from Baseline | | | | | | | |
| Natural Gas | | | 0.29% | | 0.12% | | 0.20% |
| Crude Oil | | | 0.00% | | 0.00% | | -0.01% |

Wellhead crude oil prices for onshore lower 48 production are not estimated to change meaningfully in 2020 or 2025, or over the 2020-25 period, relative to the baseline. The production-weighted average price for wellhead crude oil over the 2020 to 2025 period is not estimated to change more than 0.01 percent, relative to the baseline. Meanwhile, wellhead natural gas prices for onshore lower 48 production are estimated to increase slightly in response



to the rule in 2020 by about 0.29 percent and by about 0.12 percent in 2025, relative to the baseline. The production-weighted average price for wellhead natural gas over the 2020 to 2025 period is estimated to increase by around 0.2 percent, relative to the baseline.

Table 6-5 Net Imports of Natural Gas and Crude Oil

| | | Projection, 2020 | | Projection, 2025 | | Projection, 2020-25 | |
|---|---|---|---|---|---|---|---|
| | 2012 | Baseline | NSPS | Baseline | NSPS | Baseline | NSPS |
| Net Imports | | | | | | | |
| Natural Gas (trillion cubic feet) | 1.519 | -2.557 | -2.554 | -3.502 | -3.498 | -18.959 | -18.939 |
| Crude Oil (million barrels/day) | 8.459 | 5.513 | 5.513 | 6.073 | 6.072 | 5.857 | 5.857 |
| % Change in Net Imports | | | | | | | |
| Natural Gas | | | 0.12% | | 0.11% | | 0.11% |
| Crude Oil | | | 0.00% | | -0.02% | | 0.00% |

Meanwhile, as shown in Table 6-5, net imports of natural gas are estimated to increase slightly in 2020 and 2025 relative to the baseline (by about 0.12 percent and 0.11

percent,

respectively) relative to the baseline. Net imports of natural gas are also expected to increase by

about 0.11 percent across the 2020 to 2025 period under the rule. Crude oil imports are not

estimated to change in 2020 and to decrease slightly in 2025 by about 0.02 percent relative to the

baseline. Over the 2020 to 2025 period, net imports of crude oil are not estimated to change in

response to the rule.

## 6.3 Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C. §601 et seq.), as amended by the Small

Business Regulatory Enforcement Fairness Act (Public Law No. 104121), provides that

whenever an agency publishes a final rule after a general notice of proposed rulemaking is made,

it must prepare and make available a final regulatory flexibility analysis (FRFA), unless it

certifies that the rule, if promulgated, will not have a significant economic impact on a

substantial number of small entities (5 U.S.C. §605[b]). Small entities include small businesses,

small organizations, and small governmental jurisdictions. A FRFA describes the economic

impact of the rule on small entities and any significant alternatives to the rule that would

accomplish the objectives of the rule while minimizing significant economic impacts on small

entities. Pursuant to section 604 of the RFA, the EPA prepared a final regulatory flexibility



analysis (FRFA) that examines the impact of the final rule on small entities along with regulatory

alternatives that could minimize that impact.

Prior to publication of the proposed rule, the EPA prepared an initial regulatory flexibility

analysis (IRFA) and convened a Small Business Advocacy Review (SBAR) Panel consisting of

the Director of the Sector Policies & Programs Division of the EPA Office of Air Quality

Planning & Standards, the Administrator of the Office of Information and Regulatory Affairs

within the Office of Management and Budget, and the Chief Counsel for Advocacy of the Small

Business Administration. The IRFA and Final SBAR Panel Report can be found in the docket to

this rulemaking at EPA-HQ-OAR-2010-0505.

### 6.3.1 Reasons why the Action is Being Considered

The EPA is finalizing amendments to subpart OOOO due to reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator, which include implementation improvements. The EPA is also finalizing a new subpart, 40 CFR 60, subpart OOOOa, which includes: standards for greenhouse gas (GHG) emissions (in the form of limitations on methane) from certain facilities that are covered by current VOC standards in the oil and natural gas source category, and standards for GHG and VOC emissions from facilities across the source category that are currently unregulated, including hydraulically fractured oil well completions; fugitive emissions from well sites and compressor stations; pneumatic pumps; and centrifugal compressors, reciprocating compressors and pneumatic controllers in the transmission and storage segment. The EPA is including requirements for methane emissions in subpart OOOOa because methane is a GHG, and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.77

6.3.2 Significant Issues Raised

The EPA received comments on the proposed standards related to the potential impacts on small entities and requests for comments that were included based on the SBAR Panel

77 "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66496 (Dec. 15, 2009) ("2009 Endangerment Finding").



Recommendations. See sections VI and VIII of the preamble to the final rule and the RTC Document in Docket ID EPA-HQ-OAR-2010-0505 for more detailed responses.

Low production wells: Several commenters supported the proposed exemption of low production well sites from the fugitive monitoring requirements. Commenters noted that marginal wells generate relatively low revenue and these wells are often drilled and operated by small companies.

Response: While these commenters did provide support for the proposed low production well exemption, other commenters indicated that low production well sites have the potential to emit substantial amounts of fugitive emissions, and that a significant number of wells would be excluded from fugitive emissions monitoring based on this exemption. We did not receive data showing that low production well sites have lower emissions than non-low production well sites.

In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable and we did not finalize the proposed exclusion of low production well sites from fugitive emissions monitoring.

REC costs: Commenters stated that small operators have higher well completion costs, and typically conduct completions less frequently. Generally, small operators lack the purchasing power to get the discounted prices service companies offer to larger operators. However, commenters did not provide specific cost information.

Response: The BSER analysis is based on the averages of nationwide data. It is possible for a small operator to have higher than the nationwide average completion costs, however, the daily completion cost provided by the commenters is not significantly different than the EPA's estimate. Therefore, we do not believe that the cost of RECs disfavor small businesses.

Phase-in period for RECs: Commenters stated that the EPA should create a compliance phase-in period of at least 6 months for the REC requirements, to accommodate small operators.

Commenters stated that REC equipment is in short supply, and this will drive up REC costs.



Commenters stated that small entities lack the purchasing power of larger operators, which makes it difficult to obtain the needed equipment before the compliance period begins.

Response: We agree that complianc with the REC requirements I the final rule could be burdensome for some in the near term due to the unavailability of REC equipment. As discussed in section VI of the preamble, the final rule provides a phase-in approach that would allow a quick build-up of the REC supplied in the near term.

Alternatives to OGI technology: Several commenters indicated that the EPA should allow alternatives to OGI technology as the cost is excessive for small operators.

Response: In the final rule, the EPA is allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We believe this alternative will alleviate some of the burden on small entities.

Basing monitoring frequency on the percentage of leaking components: Commenters indicated that using a percentage of components, rather than a set number of components, to determine the frequency of surveys is also unfair to small entities since a small site will have fewer fugitive emission components than a larger site. Commenters stated that smaller entities are much more likely to operate these smaller sites, and thus are more likely to have a higher frequency survey requirements under the percentage-based system.

Response: The EPA agrees that imposing a performance based monitoring schedule would require operators to develop a program that would require extensive administration to ensure compliance. We believe that the potential for a performance-based approach to encourage greater compliance is outweighed in this case by these additional burdens and the complexity it would add. Therefore, the EPA is finalizing a fixed monitoring frequency instead of performance based monitoring.

Timing of initial fugitive monitoring periods: Commenters stated that the requirement to conduct surveys for affected facilities using OGI technology within 30 days of the well completion or within 30 days of modification is overly restrictive. Additionally, commenters stated that small operators may not be able to find vendors available to survey a small number of



wells within the required timeframe. One commenter stated that contractors will be in high demand and may give scheduling preference to larger clients versus small business entities.

Response: EPA considered these and other comments and concluded that the proposed time of 30 days within a well completion or modification is not enough time to complete the necessary preparations for the initial monitoring survey. In addition, other commenters pointed out that first date of production should be the trigger, rather than the date of well completion. Therefore, for the collection of fugitive emissions components at a new or modified well site, we are finalizing that the initial monitoring survey must take place within [insert date 1 year after publication of the final rule in the Federal Register] or within 60 days of the startup of

production, whichever is later. We believe this extended timeframe for compliance will alleviate some of the burden on smaller operators.

Third party compliance: Commenters believe that requiring third party compliance audits will be a significant burden on small entities. One commenter said that a third-party audit requirement will dramatically increase the costs of the program and have a negative competitive impact on smaller, less funded operators.

Response: While the EPA continues to believe that independent third party verification can furnish more, and sometimes better, data about regulatory compliance, we have explored alternatives to the independent third party verification. Specifically, the "qualified professional engineer" model was assessed to focus on the element of engineering design. The final rule requires a professional engineer certification of technical infeasibility of connecting a pneumatic pump to an existing control device, and a professional engineer design of closed vent systems. These certifications will ensure that the owner or operator has effectively assessed appropriate factors before making a claim of infeasibility and that the closed vent system is properly designed to verify that all emissions from the unit being controlled in fact reach the control device and allow for proper control. We believe this simplified approach will reduce the burden imposed on all affected facilities, including those owned by small businesses.



6.3.3 Small Business Administration Comments

The Chief Counsel for Advocacy of the Small Business Administration (SBA) did not file any comments in response to the proposed rule.

6.3.4 Description and Estimate of Affected Small Entities

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The EPA conducted this regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating parent entities.78 The EPA identified the size of ultimate parent entities by using the SBA size threshold guidelines.79 The criteria for size determination vary by the organization/operation category of the ultimate parent entity, as can be seen in Table 6-6.

Table 6-6 SBA Size Standards by NAICS Code

NAICS

Codes NAICS Industry Description

Size Standards

(in millions of dollars)

Size Standards

(in no. of employees)

211111 Crude Petroleum and Natural Gas Extraction - 1,250

211112 Natural Gas Liquid Extraction - 750

213111 Drilling Oil and Gas Wells - 1,000

213112 Support Activities for Oil and Gas Operations $38.5 -

486110 Pipeline Transportation of Crude Oil - 1,500

486210 Pipeline Transportation of Natural Gas $27.5 -

Sources: U.S. Census Bureau, Statistics of U.S. Businesses, 2012. <http://www.census.gov/econ/susb/>. SBA Size

Standards, 13 CFR 121. 201

We have projections of future potentially affected activities at an aggregate level, but

identifying impacts on specific entities is challenging because of the difficulty of predicting

potentially affected new or modified sources at the firm level. Because of these limitations, we

based the analysis in this FRFA on impacts estimates for the final requirements for hydraulically

fractured and re-fractured oil well completions and well site fugitive emissions. We are able to

do this because the base year activity counts for the impacts estimates (as described in the TSD)

78 See Section 2.6 of this RIA for more information on oil and natural gas industry firm characteristics and a

breakdown of firms by size at the national level.

79 U.S. Small Business Administration (SBA). 2016. Small Business Size Standards. Effective as of February 26,

2016. See: <https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf>.



for this rule were based on detailed information for 2012 in a dataset of U.S. wells. The

proprietary DrillingInfo dataset contains a variety of information including oil, condensate, and

natural gas production levels, geographic locations, as well as basin and formation information,

and information about owners/operators of wells, among other data fields.80 As described in the

TSD sections on hydraulically fractured and re-fractured oil well completions and fugitive emissions, we used the DrillingInfo dataset to identify and estimate all wells that were completed in 2012, as well as completions of hydraulically fracture or re-fractured oil wells.81 We used the field called "common operator" to identify the owner/operator of all wells in this set of new or modified 2012 wells.

While the FRFA does not incorporate potential impacts from other provisions of the final NSPS, the completions and fugitive emissions provisions represent about 98 percent of the estimated compliance costs of the final NSPS in 2020 and 2025 (Table 6-7). Not incorporating impacts from other provisions in this analysis is a limitation, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the rule in its entirety.

Table 6-7 Distribution of Estimated Compliance Costs Across Sources

| | Annualized Costs (With Product Recovery, 2012$) | | | |
|---|---|---|---|---|
| | 2020 | 2020 (%) | 2025 | 2025 (%) |
| Hydraulically-fractured and Re-fractured Oil Well Completions and Recompletions | $130,000,000 | 39% | $130,000,000 | 25% |
| Fugitive Emissions at Well Sites | $190,000,000 | 59% | $380,000,000 | 73% |
| Other Sources | $8,000,000 | 2% | $11,000,000 | 2% |
| Total Annualized Costs of Proposed NSPS | $320,000,000 | 100% | $530,000,000 | 100% |

Note: sums may not total due to independent rounding.

To identify potentially affected entities under the NSPS, the EPA combined ownership information from the DrillingInfo dataset with information drawn from the Hoover's Inc. online

80 DrillingInfo is a private company that provides information and analysis to the energy sector. More information is available at: http://info.drillinginfo.com.

81 The TSD for this proposed rule provides information on this dataset of U.S. wells. Additional details on the development of this dataset can also be found in the following docketed memo: Memorandum to Mark de Figueiredo, EPA, from Casey MacQueen and Jessica Gray, ERG. "DrillingInfo Processing Methodology". August 27, 2014.

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platform, which includes information about companies, such as NAICS codes, employee counts, and sales information.82 Note that this analysis assumes that the firms performing potentially

affected activities are also the firms performing activities in the future under the NSPS. While

likely true for many firms, this will not be the case for all firms.

The EPA matched owner/operators from the DrillingInfo dataset to companies in a

database developed from a download of oil and gas companies in Hoover's online database. The

EPA matched as many records as possible. In the instances where the DrillingInfo

owner/operator was not the highest level or company ownership, we recorded the highest level of

owner as was identifiable in Hoovers. Linking these two datasets yields information on the

NAICS, employee levels, and revenues of the owner/operators shown in the DrillingInfo dataset

to have new or modified wells in 2012.

The EPA then used the NAICS codes associated with the matched owner/operators to

determine which owner/operators should be considered to be small entities for this analysis,

based on the SBA size standards above. That said, many DrillingInfo owner/operators had no

match in Hoovers. Additionally, some Hoovers records lacked the information (employees or

revenues, depending on the NAICS) needed to make a size determination. We initially classified

these as an "unknown" size. See Table 6-8 for a summary of results of this matching exercise.

Table 6-8 No. of Completions in 2012 by Preliminary Firm Size

| | | Number of Completions, 2012 | |
|---|---|---|---|
| Firm Size | No. of Firms | Performing Well Completions Hydraulically Fractured or Re-fractured Oil Wells | All Completions |
| Small | 951 | 2,998 | 10,360 |
| Not Small | 150 | 10,674 | 22,866 |
| Unknown | 1,118 | 676 | 5,762 |
| Total | 2,219 | 14,348 | 38,988 |

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in

states where there are state rules with similar requirements as the proposed rules. Counts are slightly lower than

totals included in the impacts analysis base year estimates as some completions have no owner/operator recorded in

the dataset. Sums may not total due to independent rounding.

82 The Hoover's Inc. online platform includes company records that can contain NAICS codes, number of

employees, revenues, and assets. For more information, see: <http://www.hoovers.com>.



Upon analysis of the firms of unknown size, the EPA observed that, on average, the firms of unknown size perform fewer well completions. For this reason, we made the observation that the firms of unknown size are more likely to be small than not small. To proceed with the analysis, we reclassified these firms as small, resulting in the distribution presented in the first two columns of Table 6-9.

Table 6-9 No. of Completions in 2012 by Firm Size

| Firm Size | No. of Firms Performing Well Completions | No. of Completions, 2012: Hydraulically Fractured or Re-fractured Oil Wells | No. of Completions, 2012: All Completions |
|---|---|---|---|
| Small | 2,069 | 3,674 | 16,122 |
| Not Small | 150 | 10,674 | 22,866 |
| Total | 2,219 | 14,348 | 38,988 |

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in states where there are state rules with similar requirements as the proposed rules. Counts are slightly lower than totals included in the impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

### 6.3.5 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to

Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOa are owners or operators of new, modified or

reconstructed oil and natural gas affected facilities as defined under the rule. None of the

facilities in the United States are owned or operated by state, local, tribal or the Federal

government. All facilities are privately owned for-profit businesses. The requirements in this



action result in an industry recording keeping and reporting burden associated with review of the

requirements for all affected entities, gathering relevant information, performing initial

performance tests and repeat performance tests if necessary, writing and submitting the

notifications and reports, developing systems for the purpose of processing and maintaining

information, and training personnel to be able to respond to the collection of information. The

estimated average annual burden (averaged over the first 3 years after the effective date of the

standards) for the recordkeeping and reporting requirements in subpart OOOOa for the

2,554 owners and operators that are subject to the rule is 98,438 labor hours, with an annual

average cost of $3,361,074. The annual public reporting and recordkeeping burden for this

collection of information is estimated to average 20 hours per response. Respondents must

monitor all specified criteria at each affected facility and maintain these records for 5 years.

Burden is defined at 5 CFR 1320.3(b).

6.3.5.1 Methodology for Estimating Compliance Cost Impacts on Small Entities

This section describes how we project the 2012 base year estimates of incrementally

affected facilities to 2020 and 2025 levels, how we estimate costs at the firm level from these

activity estimates, and how we estimated sales for small entities when available data on sales are

incomplete.

New and modified hydraulically fractured oil well completions and well sites in this

FRFA are based on the same growth rates used to project future activities as described in the

TSD and are consistent with other analyses in this RIA. These growth rates are consistent with

the drilling activity in the 2015 Annual Energy Outlook. These growth rates are applied to the

2012 base year estimates for each firm in the database.

Table 6-10 presents future year estimates of incrementally affected new and modified sources.

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Table 6-10 No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size

| Firm Size Performing Well Completions | No. of Incrementally Affected Sources, 2020 | | | No. of Incrementally Affected Sources, 2025 | | |
|---|---|---|---|---|---|---|
| | Hydraulically Fractured or Refractured Oil Wells | Gas Well Sites | Oil Well Sites | Hydraulically Fractured or Refractured Oil Wells | Gas Well Sites | Oil Well Sites |
| Small | 3,500 | 5,600 | 33,000 | 3,800 | 11,000 | 68,000 |
| Not Small | 10,000 | 11,000 | 44,000 | 11,000 | 24,000 | 86,000 |
| Total | 14,000 | 17,000 | 77,000 | 15,000 | 35,000 | 160,000 |

Note: Sums may not total due to independent rounding. Assumes well sites have two wells apiece.

This approach assumes that no other firms perform potentially affected activities and firms performing these activities in 2012 will continue to do so in 2020 and 2025. Again, the analysis in this FRFA is meant to be illustrative of impacts on small entities. Exact predictions of future activities at the firm level is not possible.

Once the future year activities were estimated we allocated compliance costs across small

entities based upon the costs estimated in the TSD and consistently with other analyses in this

RIA. These cost estimates include estimates of revenue from natural gas recovery at the assumed

value of $4/Mcf in 2012 dollars, again consistent with other analyses in this RIA. For

hydraulically fractured and re-fractured oil well completions, we assumed each small entity is

required to perform RECs and combustion in the same proportions assumed in the TSD and RIA.

We also assumed the same proportion would be exploratory or delineation wells as the TSD and

RIA. Table 6-11 shows the distribution of compliance costs estimates across firm size and year.

Table 6-11 Distribution of Estimated Compliance Costs1 across Firm Size Classes

| | | Annualized Compliance Costs (2012$) | |
|---|---|---|---|
| Firm Size | No. of Firms | 2020 | 2025 |
| Small | 2,069 | 110,000,000 | 190,000,000 |
| Not Small | 150 | 200,000,000 | 320,000,000 |
| Total | 2,219 | 310,000,000 | 510,000,000 |

1 Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil

well completions and well-site fugitive emissions. As described in Section 6.1.3, these provisions account for the

large majority of the rule's potential impact in 2020 and 2025.

Note: sums may not total due to independent rounding.



In order to estimate the cost-to-sales ratio, we again combined information from Hoovers

and the DrillingInfo databases. The Hoovers database has sales information for some, but not all,

small entities estimated in this FRFA analysis to have impacts. To supplement the sales

information, we estimated 2012 sales by multiplying 2012 oil and natural gas production levels

reported in the DrillingInfo database by assumed oil and natural gas prices at the wellhead. For

natural gas, we assumed the same $4/Mcf for natural gas.83 For oil prices, we estimated revenues

using two alternative prices, $70/bbl and $50/bbl. In the results, we call the case using $70/bbl

the "primary scenario" and the case using the $50/bbl as the "low oil price scenario".84 In the

instances where the 2012 production-derived revenues exceeded the Hoovers revenues, we

replaced the Hoovers estimate with the production-derived estimate as more likely to be an

accurate estimate of sales for 2012.

6.3.5.2 Compliance Cost Impact Estimate Results

This section presents results of the cost-to-sales ratio analysis for both the primary

scenario and the low oil price scenario. The percent of small entities with cost-to-sales ratios

exceeding 1 percent and 3 percent in 2020 and 2025 are greater under the low oil price scenario,

as would be expected due to lower estimated sales revenues from a lower oil price. Also, as

expected, the entities with cost-to-sales ratios greater than 1 percent and greater than 3 percent

increase from 2020 to 2025 in both the main case and the low oil price scenario as affected

sources accumulate under the NSPS.

83 The U.S. Energy Information Administration's 2015 Annual Energy Outlook projects 2020 Henry Hub natural gas

prices to be $4.88/MMBtu in its reference case and $4.30/MMBtu in its "low oil" price case in 2013 dollars.

Available at: <http://www.eia.gov/beta/aeo/#/?id=14-AEO2015>. After adjusting to $/Mcf (using the conversion

of 1 MMBtu = 1.208 Mcf) in 2012 dollars (using the GDP-Implicit Price Deflator), these prices are $4.80/Mcf in

the reference case and $4.323/Mcf in the low oil price case. Rounding down to $4/Mcf likely under-estimates

sales.

84 The 2015 Annual Energy Outlook projects wellhead oil prices to be $75.16/bbl in its reference case and

$54.10/bbl in its "low oil" price case in 2013 dollars. Available at: <http://www.eia.gov/beta/aeo/#/?id=14-

AEO2015>. After adjusting to 2012 dollars (using the GDP-Implicit Price Deflator), these prices are $74.00/bbl

in the reference case and $53.27/bbl in the low oil price case.



Table 6-12 Compliance Costs-to-Sales1 Ratios across Firm Size Classes for Primary

Scenario and Low Oil Price Scenario2

2020 (Main Case) 2020 (Low Oil Price Case)

No. of Small

Entities

% of Small

Entities

No. of Small

Entities

% of Small

Entities

No. of Small Entities 2,031 - 2,043 -

Greater than 1 percent 564 28% 648 32%

Greater than 3 percent 289 14% 344 17%

2025 (Main Case) 2025 (Low Oil Price Case)

No. of Small

Entities

% of Small

Entities

No. of Small

Entities

% of Small

Entities

No. of Small Entities 2,031 - 2,043 -

Greater than 1 percent 824 41% 924 45%

Greater than 3 percent 419 21% 502 25%

1 Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil

well completions and well-site fugitive emissions. These provisions account for the large majority of the rule's

potential impact in 2020 and 2025.

2 In the main case, the wellhead prices are assumed to be $4/Mcf for natural gas and $70/bbl for crude oil. In the low

oil price case, the wellhead prices are assumed to be $4/Mcf for natural gas and $50/bbl for crude oil.

6.3.5.3 Caveats and Limitations

The analysis above is subject to a number of caveats and limitations, many of which we

discussed in the presentation of methods and results. It is useful, however, to present a complete

list of the caveats and limitations here.

• Because of data limitations, the analysis presented in the FRFA only examines impacts

on requirements for hydraulically fractured and re-fractured oil well completions and

well site fugitive emissions. While impacts from these requirements constitute a large

proportion of the estimated impacts from the final NSPS, the omission of the estimated

costs of other requirements leads to a relative under-estimation of the impacts on small

entities. Also, the impacts from other requirements may affect firms that are not

drilling wells, such as pipeline transmission firms.

• Not all owner/operators listed in the DrillingInfo database could be identified in the

Hoovers database. These owner/operators tend to have developed relatively few new

or modified wells in 2012. As a result, we assumed these were small entities, whereas these entities may actually be subsidiaries of larger enterprises. While the impacts estimates are not affected in the aggregate by this assumption, the assumption likely leads to an over-estimate of the impact on small entities for the provisions examined.

• The analysis assumes the same population of entities completing wells in 2012 are also completing wells in 2020 and 2025, according to growth rates developed for the entire



sector. In the future, many of these firms will complete fewer or more wells, and other firms will complete wells. All of these firms combined may complete new or modified wells at higher or lower rates depending on economics and technological factors that are largely unpredictable.

• The approach used to estimate sales for the cost-to-sales ratio might over-estimate or under-estimate sales depending upon the accuracy of the information in the underlying databases and the market prices ultimately faced in 2020 and 2025.

6.3.6 Regulatory Flexibility Alternatives

The EPA considered three major options for this final rule. The option EPA is finalizing contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. This option requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at the affected newly drilled or refractured oil and natural gas well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Additionally this option requires reductions from centrifugal compressors, reciprocating compressors, pneumatic controllers, and pneumatic pumps throughout the oil and natural gas source category.

The other options considered differ from the finalized option with respect to the requirements for fugitive emissions. One option exempted low production well sites from the well site fugitive requirements. This less stringent option was analyzed as an alternative to reduce burden on small entities. However, it was rejected because we believe that low production well sites have the same type of equipment and components as production well sites with production greater than 15 boe per day. Since we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site.

This would indicate that the emissions from low production well sites could be similar to that of nonlow production well sites. Additionally, we did not receive data showing that low production well sites have lower methane or VOC emissions than well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In discussions with industry stakeholders, they indicated that well site fugitive emissions are not based on production, but rather on the number of pieces of

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equipment and components. Therefore, we believe that the emissions from low production and non-low production well sites are comparable, and low production well sites were included in the selected option.

Lastly, the more stringent option required quarterly monitoring for all sites under the fugitive emissions program. This option lead to greater emission reductions, however it was not selected because it increased costs, resulting in a net effect of lower net benefits compared to the finalized option.

In addition, the EPA is preparing a Small Entity Compliance Guide to help small entities comply with this rule. The guide will be available on the World Wide Web approximately 60 days after promulgation of the rule, at https://www3.epa.gov/airquality/oilandgas/implement.html.

The EPA notes that the IRFA includes numerous recommendations made by the SBAR Panel[85]. The EPA considered these recommendations during the development of the proposal and final rule. The rationale for the EPA's acceptance or rejection of each recommendation can be found in the relevant discussion of each emission source throughout the preamble to the proposal, final rule, and RTC. Though all comments were seriously considered, the EPA is unable to incorporate all suggestions without compromising the effectiveness of the final regulation. Changes to the rule from proposal that may benefit small entities due to comments received include allowing both OGI and Method 21 as acceptable monitoring technology, replacing a performance based monitoring schedule with a fixed frequency, lengthening the time

of initial fugitive monitoring from within 30 days to the later of either [insert date 1 year after

publication of the final rule in the Federal Register] or with 60 days of the startup of

production, and simplified the third party verification of technical infeasibility requirements.

Though these are not monetized, we believe the flexibility and simplifications these changes

have added to the rule result in a reduced burden on small entities.

85 The final SBAR Panel report is found at <https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-

2010-0505-4959>.



## 6.4 Employment Impact Analysis

In addition to addressing the costs and benefits of the final rule, the EPA has analyzed the

impacts of this rulemaking on employment, which are presented in this section.86 While a

standalone analysis of employment impacts is not included in a standard cost-benefit analysis,

such an analysis is of particular concern in the current economic climate given continued interest

in the employment impact of regulations such as this final rule. Executive Order 13563, states,

"Our regulatory system must protect public health, welfare, safety, and our environment while

promoting economic growth, innovation, competitiveness, and job creation." 87 A discussion of

compliance costs, including reporting and recordkeeping requirements, is included in Section 3

of this RIA. This analysis uses detailed engineering information on labor requirements for each

of the control strategies identified in this final rule in order to estimate partial employment

impacts for affected entities in the oil and gas industry. These bottom-up, engineering-based

estimates represent only one portion of potential employment impacts within the regulated

industry, and do not represent estimates of the net employment impacts of this rule. First, this

section presents an overview of the various ways that environmental regulation can affect

employment. The EPA continues to explore the relevant theoretical and empirical literature and

to seek public comments in order to ensure that the way the EPA characterizes the employment effects of its regulations is valid and informative. The section concludes with partial employment impact estimates that rely on engineering-based information for labor requirements for each of the control strategies identified by the rule.

6.4.1 Employment Impacts of Environmental Regulation

From an economic perspective labor is an input into producing goods and services; if a regulation requires that more labor be used to produce a given amount of output, that additional labor is reflected in an increase in the cost of production. Moreover, when the economy is at full employment, we would not expect an environmental regulation to have a net impact on overall employment because labor is being shifted from one sector to another. On the other hand, in

86 The employment analysis in this RIA is part of the EPA's ongoing effort to "conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]" pursuant to CAA section 321(a).

87 Executive Order 13563 (January 21, 2011). Improving Regulation and Regulatory Review. Section 1. General Principles of Regulation, Federal Register, Vol. 76, Nr. 14, p. 3821.



periods of high unemployment, net employment effects (both positive and negative) are possible. For example, an increase in labor demand due to regulation may result in a short-term net increase in overall employment as workers are hired by the regulated sector to help meet new requirements (e.g., to install new equipment) or by the environmental protection sector to produce new abatement capital resulting in hiring previously unemployed workers. When significant numbers of workers are unemployed, the opportunity costs associated with displacing jobs in other sectors are likely to be higher. And, in general, if a regulation imposes high costs and does not increase the demand for labor, it may lead to a decrease in employment. The responsiveness of industry labor demand depends on how these forces all interact. Economic theory indicates that the responsiveness of industry labor demand depends on a number of factors: price elasticity of demand for the product, substitutability of other factors of production, elasticity of supply of other factors of production, and labor's share of total production costs.

Berman and Bui (2001) put this theory in the context of environmental regulation, and suggest that, for example, if all firms in the industry are faced with the same compliance costs of regulation and product demand is inelastic, then industry output may not change much at all.

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing environmental regulations. When a regulation is promulgated, one typical response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. On the other hand, the closure of plants that choose not to comply - and any changes in production levels at plants choosing to comply and remain in operation - occur after the compliance date, or earlier in anticipation of the compliance obligation. Environmental regulation may increase revenue and employment in the environmental technology industry. While these increases represent gains for that industry, they translate into costs to the regulated industries required to install the equipment.

Environmental regulations support employment in many basic industries. Regulated firms either hire workers to design and build pollution controls directly or purchase pollution control devices from a third party for installation. Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment-much like they hire workers to produce more output. In addition to the increase in employment in the environmental



protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment.

Berman and Bui (2001) demonstrate using standard neoclassical microeconomics that environmental regulations have an ambiguous effect on employment in the regulated sector. The theoretical results imply that the effect of environmental regulation on employment in the regulated sector is an empirical question. Berman and Bui (2001) developed an innovative approach to examine how an increase in local air quality regulation that reduces nitrogen oxides

(NOX) emissions affects manufacturing employment in the South Coast Air Quality Management District (SCAQMD), which incorporates Los Angeles and its suburbs. During the time frame of their study, 1979 to 1992, the SCAQMD enacted some of the country's most stringent air quality regulations. Using SCAQMD's local air quality regulations, Berman and Bui identify the effect of environmental regulations on net employment in the regulated industries.88 The authors find that "while regulations do impose large costs, they have a limited effect on employment" (Berman and Bui, 2001, p. 269). Their conclusion is that local air quality regulation "probably increased labor demand slightly" but that "the employment effects of both compliance and increased stringency are fairly precisely estimated zeros, even when exit and dissuaded entry effects are included" (Berman and Bui, 2001, p. 269).89

While there is an extensive empirical, peer-reviewed literature analyzing the effect of environmental regulations on various economic outcomes including productivity, investment, competitiveness as well as environmental performance, there are only a few papers that examine the impact of environmental regulation on employment, but this area of the literature has been growing. As stated previously in this RIA section, empirical results from Berman and Bui (2001) suggest that new or more stringent environmental regulations do not have a substantial impact on net employment (either negative or positive) in the regulated sector. Similarly, Ferris, Shadbegian, and Wolverton (2014) also find that regulation-induced net employment impacts are

88 Berman and Bui include over 40 4-digit SIC industries in their sample.

89 Including the employment effect of exiting plants and plants dissuaded from opening will increase the estimated impact of regulation on employment.



close to zero in the regulated sector. Furthermore, Gray et al (2014) find that pulp mills that had to comply with both the air and water regulations in the EPA's 1998 "Cluster Rule" experienced relatively small and not always statistically significant, decreases in employment. Nevertheless, other empirical research suggests that more highly regulated counties may generate fewer jobs than less regulated ones (Greenstone 2002, Walker 2011). However, the methodology used in

these two studies cannot estimate whether aggregate employment is lower or higher due to more

stringent environmental regulation, it can only imply that relative employment growth in some

sectors differs between more and less regulated areas. List et al. (2003) find some evidence that

this type of geographic relocation, from more regulated areas to less regulated areas may be

occurring. Overall, the peer-reviewed literature does not contain evidence that environmental

regulation has a large impact on net employment (either negative or positive) in the long run

across the whole economy.

While the theoretical framework laid out by Berman and Bui (2001) still holds for the

industries affected under these emission guidelines, important differences in the markets and

regulatory settings analyzed in their study and the setting presented here lead us to conclude that

it is inappropriate to utilize their quantitative estimates to estimate the net employment impacts

from this final regulation. In particular, the industries used in these two studies as well as the

timeframe (late 1970's to early 1990's) are quite different than those in this final NSPS.

Furthermore, the control strategies analyzed for this RIA include implementing RECs, reducing

fugitive emissions, and reducing emissions from pneumatic controllers, pumps, and reciprocating

and centrifugal compressors, which are very different than the control strategies examined by

Berman and Bui.[90] For these reasons we conclude there are too many uncertainties as to the

transferability of the quantitative estimates from Berman and Bui to apply their estimates to

quantify the net employment impacts within the regulated sectors for this regulation, though

these studies have usefulness for qualitative assessment of employment impacts.

The preceding sections have outlined the challenges associated with estimating net

employment effects in the regulated sector and in the environmental protection sector. These

challenges make it very difficult to accurately produce net employment estimates for the whole

90 More detail on how emission reductions expected from compliance with this rule can be found in Section 3 of this

RIA.

economy that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy. Given the difficulty with estimating national impacts of regulations, the EPA has not generally estimated economy-wide employment impacts of its regulations in its benefit-cost analyses. However, in its continuing effort to advance the evaluation of costs, benefits, and economic impacts associated with environmental regulation, the EPA has formed a panel of experts as part of the EPA's Science Advisory Board (SAB) to advise the EPA on the technical merits and challenges of using economy-wide economic models to evaluate the impacts of its regulations, including the impact on net national employment.[91] Once the EPA receives guidance from this panel it will carefully consider this input and then decide if and how to proceed on economy-wide modeling of net employment impacts of its regulations.

6.4.2 Labor Estimates Associated with Final Requirements

Section 2 of the RIA, in Table 2-17 and Table 2-18, presents background information on employment and wages in the oil and natural gas industry. As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in six oil and natural gas-related NAICS codes from 1990 to 2014.[92] The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 314,000 in 1999, but rebounding to a 2014 peak of about 660,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry. From 1990 to 2014, average wages for the oil and natural gas industry increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2014 for the NAICS codes associated with the oil and natural gas industry.

The focus of this part of the analysis is on labor requirements related to the compliance actions for the final rule of the affected entities within the oil and natural gas sector. We do not estimate any potential changes in labor outside of the affected sector, and due to data and

91 For further information see:
http://yosemite.epa.gov/sab/sabproduct.nsf/0/07E67CF77B54734285257BB0004F87ED?OpenDocument

92 NAICS 211111, 21112, 213111, 213112, 486110, and 486210.



methodology limitations we do not estimate net employment impacts for the affected sector, apart from the partial estimate of the labor requirements related to control strategies. This analysis estimates the labor required to the install, operate, and maintain control equipment and activities, as well as to perform new reporting and recordkeeping requirements.

It is important to highlight that, unlike the typical case where a firm often has to reduce production in order to reduce output of negative production externalities (i.e., emissions), many of the emission controls required by the final NSPS will simultaneously increase production and reduce negative externalities. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. Therefore, new labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions. However, these rules may require unprofitable investments for some operators, and there is a possibility that these producers decrease output in response and create downward pressure on labor demand, both in the regulated sector and on those sectors using natural gas as an input. This RIA does not include quantified estimates of these potential adverse effects on the labor market due to data limitations and theoretical challenges, as described above.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because the EPA does not currently have this information. The labor requirements analysis uses a bottom-up engineeringbased methodology to estimate employment impacts. The engineering cost analysis summarized in Chapter 3 of this RIA includes estimates of the labor requirements associated with implementing the regulations. Each of these labor changes may be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate

cannot be used to make assumptions about the specific number of employees involved or

whether new jobs are created for new employees.

The results of this employment analysis of the NSPS are presented in Table 6-13 through



Table 6-16 for 2020 and 2025 for individual sources regulated under this rule. Table 6-17

presents summary-level labor impacts for all sources. The tables break down the installation,

operation, and maintenance estimates by type of pollution control evaluated in the RIA and

present both the estimated hours required and the conversion of this estimate to FTE. The labor

information is based upon the cost analysis presented in the TSD that supports this rule, based

upon analysis presented in the RIA developed for the 2012 NSPS and NESHAP Amendments for

the Oil and Natural Gas Sector (U.S. EPA, 2012). In addition, for the final NSPS, reporting and

recordkeeping requirements were estimated for the entire rule rather than by anticipated control

requirements. The reporting and recordkeeping estimates are consistent with estimates the EPA

submitted as part of its Information Collection Request (ICR), the estimated costs which are

included in the cost estimates presented in Chapter 3.

Table 6-13 presents estimates of labor requirements for hydraulically fractured oil well

completions. The REC and completion combustion requirements are associated with certain new

and existing oil well completions. While individual well completions take place over a short

period of time (days to a few weeks), the overall industry completes new wells and re-completes

some existing wells every year. Because of the continuing nature of new and existing well

completions, annually, at the industry level, we report the REC-related labor requirements in

annual units.

The per-unit estimates of one-time labor requirements associated with implementing

RECs and completion combustion are drawn from the labor requirements estimated for

implementing RECs on hydraulically fractured well completions in EPA (2012). However, the

labor requirements in that report were based upon a completion that is assumed to last seven days

(218 hours per completion for a REC or 22 hours labor per completion for completion

combustion). In this analysis, completion events for hydraulically fractured oil wells are assumed

to last three days, so we multiply the seven-day requirements by 3/7 (93 hours per completion for

a REC or 9 hours labor per completion for completion combustion).



Table 6-13 Estimates of Labor Required to Comply with NSPS for Hydraulically

Fractured Oil Well Completions, 2020 and 2025

Emissions Source/Control

Projected No.

of

Incrementally

Affected

Units (2020)

Per Unit

Onetime

Labor

Estimate

(hours)

Per Unit

Annual

Labor

Estimate

(hours)

Total

One-

Time

Labor

Estimate

(hours)

Total

Annual

Labor

Estimate

(hours)

Onetime

FTE

Annual

FTE

2020

Hydraulically Fractured Oil Well Completions and

Recompletions

Completions where REC

and completion

combustion is required

7,500 0 93 0 700,000 0 340

Completions where

completion combustion is

required

5,600 0 9 0 53,000 0 25

Total 13,000 N/A N/A 0 760,000 0 360

2025

Hydraulically Fractured Oil Well Completions and

Recompletions

Completions where REC

and completion

combustion is required

8,000 0 93 0 750,000 0 360

Completions where

completion combustion is

required

6,000 0 9 0 57,000 0 27

Total 14,000 N/A N/A 0 800,000 0 390

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per-unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-14 presents estimates of labor requirements for fugitive emissions. Consistent with the cost estimates for fugitive emissions presented in Section 5 of the TSD, we estimate labor associated with company-level activities and activities at field sites. Company-level activities include one-time activities such as planning the company's fugitive emissions program and annual requirements such as reporting and recordkeeping. Field-level activities include semiannual inspection and repair of leaks. It is important to note, however, that the compliance costs estimates for leak inspection were based upon an estimate of the costs to hire a contractor to provide the inspection service, but the source providing this information does not have a breakdown of the labor component of the rental cost. As a result, the labor requirements for the

fugitives program remain uncertain.



Table 6-14 Estimates of Labor Required to Comply with NSPS for Fugitive Emissions,

2020 and 2025

Emissions Source

Emissions

Control

Projected No.

of

Incrementally

Affected

Units (2020)

Per Unit

Onetime

Labor

Estimate

(hours)

Per Unit

Annual

Labor

Estimate

(hours)

Total

One-

Time

Labor

Estimate

(hours)

Total

Annual

Labor

Estimate

(hours)

Onetime

FTE

Annual

FTE

2020

Well Sites

Company-level Planning 4,300 120 0.0 500,000 0 240 0

Site-level

Monitoring

and

Maintenance

94,000 0.0 14 0 1,300,000 0 640

Gathering and Boosting Stations

Company-level Planning 480 120 0.0 57,000 0 27 0

Site-level

Monitoring

and

Maintenance

480 0.0 110 0 52,000 0 25

Transmission Compressor Stations

Company-level Planning 20 120 0.0 2,400 0 1 0

Site-level

Monitoring

and

Maintenance

20 0.0 110 0 2,100 0 1

Storage Compressor Stations

Company-level Planning 25 120 0.0 3,000 0 1 0

Site-level

Monitoring

and

Maintenance

25 0.0 210 0 5,300 0 3

Total 94,000 N/A N/A 560,000 1,400,000 270 660

2025

Well Sites

Company-level Planning 4,300 120 0.0 500,000 0 240 0

Site-level

Monitoring

and

Maintenance

190,000 5.4 14 0 2,700,000 0 1,300

Gathering and Boosting Stations

Company-level Planning 480 120 0.0 57,000 0 27 0

Site-level

Monitoring

and

Maintenance

960 0.0 110 0 100,000 0 50

Transmission Compressor Stations

Company-level Planning 20 120 0.0 2,400 0 1 0

Site-level

Monitoring

and

Maintenance

40 0.0 110 0 4,300 0 2

Storage Compressor Stations

Company-level Planning 25 120 0.0 3,000 0 1 0

Site-level

Monitoring

and

Maintenance

50 0.0 210 0 11,000 0 5

Total 190,000 N/A N/A 560,000 2,800,000 270 1,400

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by theper

unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to

independent rounding.

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Most labor required for fugitive emissions is needed at well sites in the field, which

number in the thousands. Note that the labor requirements estimates increase from 2020 to 2025

as the number of sites regulated under the final NSPS accumulates.

Table 6-15 presents labor requirement estimates for monitoring and maintainence

requirements for reciprocating compressors and routing emissions to a control device for

centrifugal compressors. Like the estimates for completions, the per unit labor estimates were

based on EPA (2012). As relatively little labor is required for reciprocating compressors and

relatively few affected centrifugal compressors are expected in the future, the estimates of both

one-time and on-going labor requirements for compressor requirements are minimal.

Table 6-15 Estimates of Labor Required to Comply with NSPS for Reciprocating and

Centrifugal Compressors, 2020 and 2025

Emissions Source

Emissions

Control

Projected

No. of

Incr.

Affected

Units

Per-unit

Onetime

Labor

Est.

(hrs)

Per-unit

Annual

Labor

Est.

(hrs)

Total

One-

Time

Labor

Estimate

(hrs)

Total

Annual

Labor

Estimate

(hrs)

Onetime

FTE

Annual

FTE

2020

Compressors

Reciprocating

Monitoring

and

Maintenance

160 1 1 160 160 0 0

Centrifugal

Route to

Control

5 360 0 1,800 0 1 0

Total 170 N/A N/A 2,000 160 1 0

2025

Compressors

Reciprocating

Monitoring

and

Maintenance

320 1 1 160 320 0 0

Centrifugal

Route to

Control

10 360 0 1,800 0 1 0

Total 330 N/A N/A 2,000 320 1 0

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 6-16 presents the labor requirement estimates for requirements applying to pneumatic controllers and pneumatic pumps. Note that pneumatic controllers have no one-time or continuing labor requirements. While the controls do require labor for installation, operation,



and maintenance, the required labor is less than that of the controllers that would be used absent the regulation (U.S. EPA, 2012). In this instance, we assume the incremental labor requirements are zero. Meanwhile, we are currently unable to estimate the labor associated with pneumatic pump control activities.

Table 6-16 Estimates of Labor Required to Comply with NSPS for Pneumatic Controllers and Pumps, 2020 and 2025

Emissions

Source

Emissions

Control
Projected
No. of Incr.
Affected
Units
Per-unit
Onetime
Labor
Est.
(hrs)
Per-unit
Annual
Labor
Est.
(hrs)
Total
One-
Time
Labor
Estimate
(hrs)
Total
Annual
Labor
Estimate
(hrs)
Onetime
FTE
Annual
FTE
2020
Pneumatic
Controllers
Emissions
Limit
480 0 0 0 0 0 0
Pneumatic
Pumps
Route to

Control

3,900 N/A N/A N/A N/A N/A N/A

2025

Pneumatic

Controllers

Emissions

Limit

960 0 0 0 0 0 0

Pneumatic

Pumps

Route to

Control

7,900 N/A N/A N/A N/A N/A N/A

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the

per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum

due to independent rounding.

Table 6-17 presents the labor estimates across all emissions sources. Two main categories

contain the majority of the labor requirements for the final NSPS: implementing reduced

emissions completions (REC) at hydraulically fracture oil well completions and fugitive

emissions detection and repair at well sites. The up-front labor requirement to comply with the

final NSPS is estimated at 270 FTEs in 2020 and in 2025. The annual labor requirement to

comply with final NSPS is estimated at about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. We

note that this type of FTE estimate cannot be used to identify the specific number of employees

involved or whether new jobs are created for new employees, versus displacing jobs from other

sectors of the economy.



Table 6-17 Estimates of Labor Required to Comply with NSPS, 2020 and 2025

Emissions Source

Projected No.

of

Incrementally

Affected

Units (2020)

Total One-

Time Labor

Estimate

(hours)

Total Annual

Labor Estimate

(hours)

One-time

FTE

Annual

FTE

2020

Hydraulically Fractured and

Re-fractured Oil Well

Completions

13,000 0 760,000 0 360

Fugitive Emissions 94,000 560,000 1,400,000 270 660

Pneumatic Controllers 480 0 0 0 0

Pneumatic Pumps 3,900 N/A N/A N/A N/A

Reciprocating Compressors 160 160 160 0 0

Centrifugal Compressors 5 1,800 0 1 0

Reporting and

Recordkeeping Requirements

All 0 180,000 0 88

Total 110,000 570,000 2,300,000 270 1,100

2025

Hydraulically Fractured and

Re-fractured Oil Well

Completions

14,000 0 800,000 0 390

Fugitive Emissions 190,000 560,000 2,800,000 270 1,400

Pneumatic Controllers 960 0 0 0 0

Pneumatic Pumps 7,900 N/A N/A N/A N/A

Reciprocating Compressors 320 160 320 0 0

Centrifugal Compressors 10 1,800 0 1 0

Reporting and

Recordkeeping Requirements

All 0 180,000 0 88

Total 220,000 570,000 3,800,000 270 1,800

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Rounded to two

significant digits. Totals may not sum due to independent rounding.

6.5 References

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United States
Environmental Protection
Agency
Office of Air Quality Planning and Standards
Health and Environmental Impacts Division
Research Triangle Park, NC
Publication No.
EPA-452/R-16-002
May 2016